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Baugh et al.

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[54] **BREECH BLOCK HANGER SUPPORT**

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[51] **Int. Cl.**^{3} **F16L 15/00**

[52] **U.S. Cl.** .... **285/84;** 285/93; 285/96; 285/106; 285/108; 285/133 A; 285/143; 285/308; 285/351; 285/391; 285/DIG. 18

[58] **Field of Search** .... 285/142, 24, 143, 93, 285/140, 391, 144, 27, 145, 146, 147, 133 A, 18, 39, 84, 96, 106, 108, 308, 351, DIG. 18; 166/348, 380

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[57] **ABSTRACT**

A breech block hanger support member for a subsea wellhead assembly for wells having a working pressure up to approximately 15,000 psi. The assembly includes a wellhead, the support member, a packoff for sealing the support member, and one or more other casing hangers supported by the support member. The support member is connected to the wellhead for itself suspending casing, for supporting at least one other casing hanger and casing, and for containing the working pressure. Breech block teeth are provided on the wellhead and support member to permit the support member to be stabbed into the wellhead and rotated less than 360° for completing the connection therebetween. The teeth include groupings of spaced-apart no-lead teeth having slots therebetween. The slots provide a flow way for passing well fluids. The support member further includes an upper annular flange for arresting its downward movement within the wellhead. This flange includes flutes aligned with the slots for passing well fluids. The support member includes threads for connecting to the top of a casing string. The upper surface of the flange provides a bearing surface for supporting another casing hanger. The bearing surface of the support member will support all of the casing and tubing load and contain the working pressure. The bearing surface between the breech block teeth is greater than that provided by the support member for the other casing hangers. The packoff seals the support member with the wellhead and other casing hangers.

51 Claims, 11 Drawing Figures

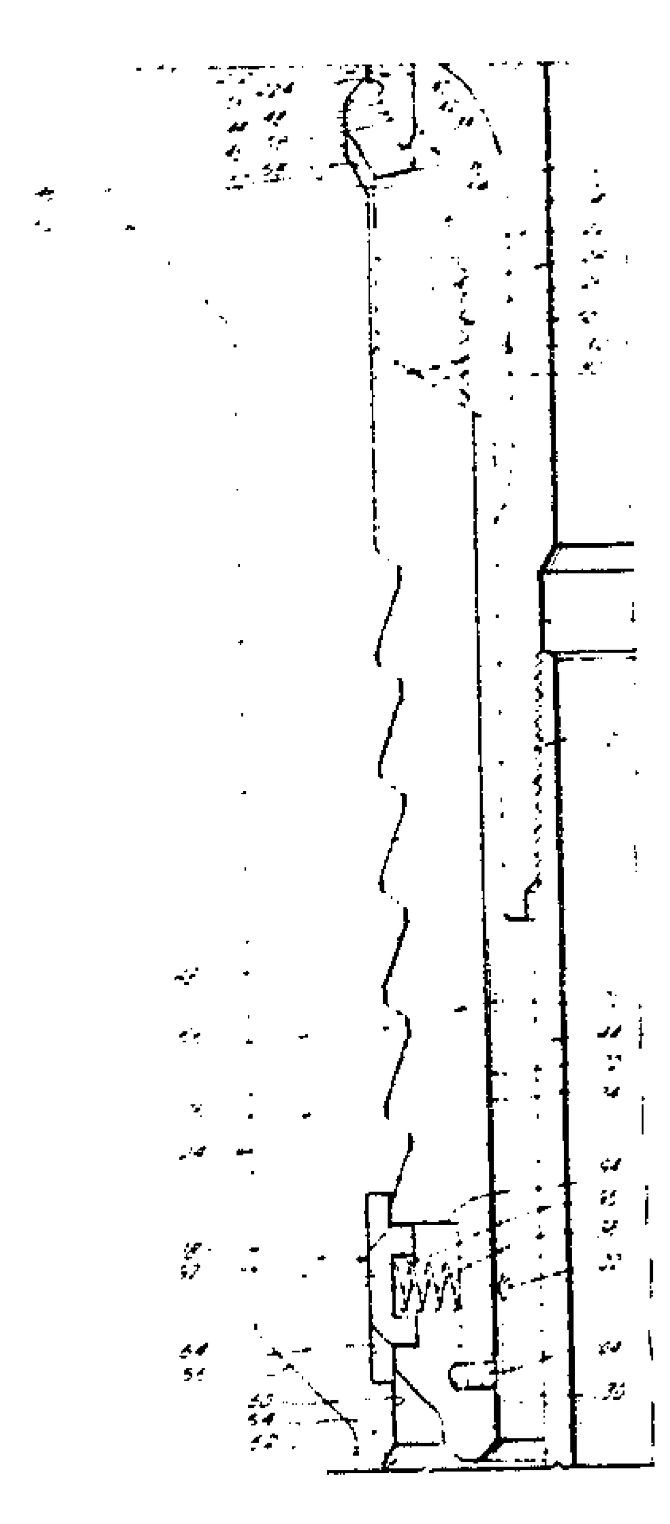


Fig. 2C

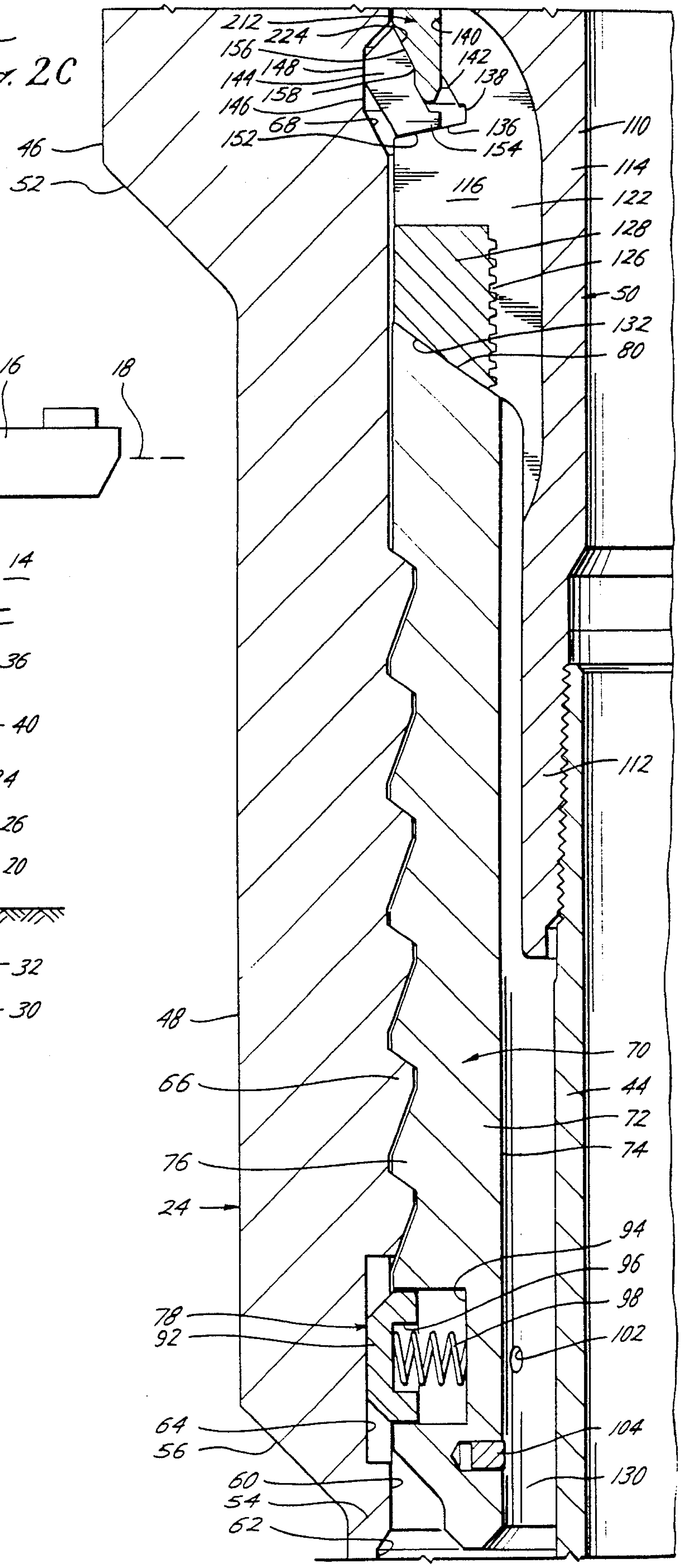
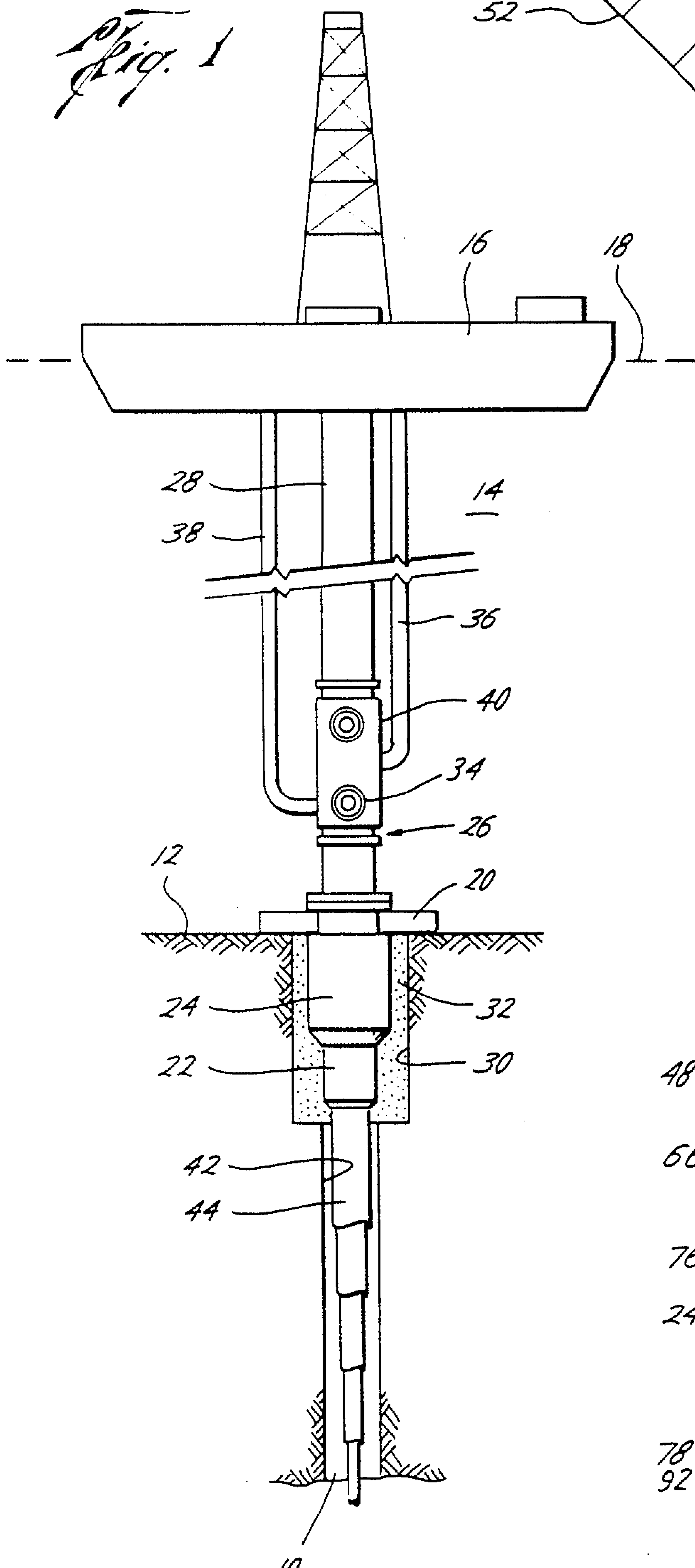


Fig. 1



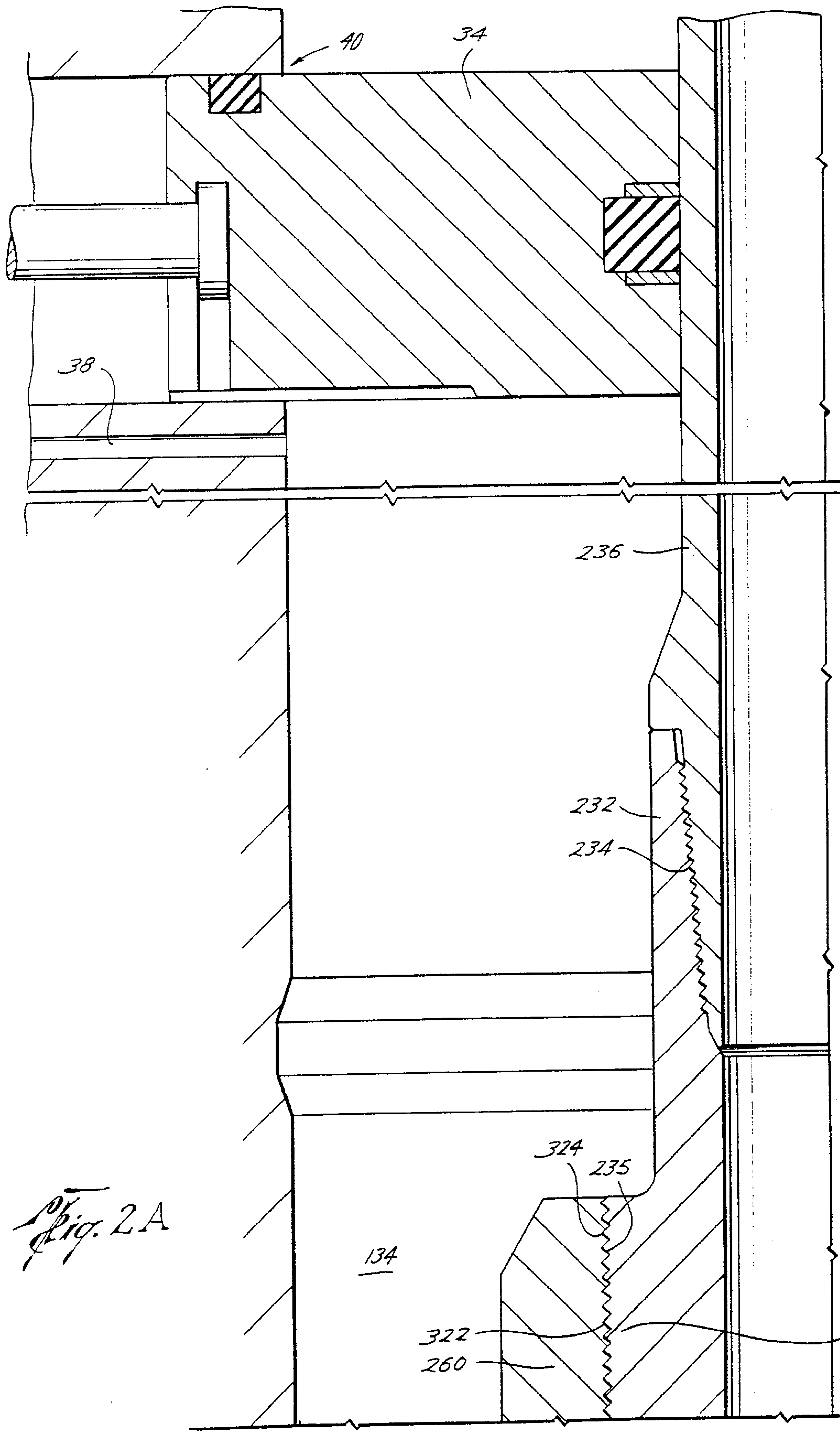
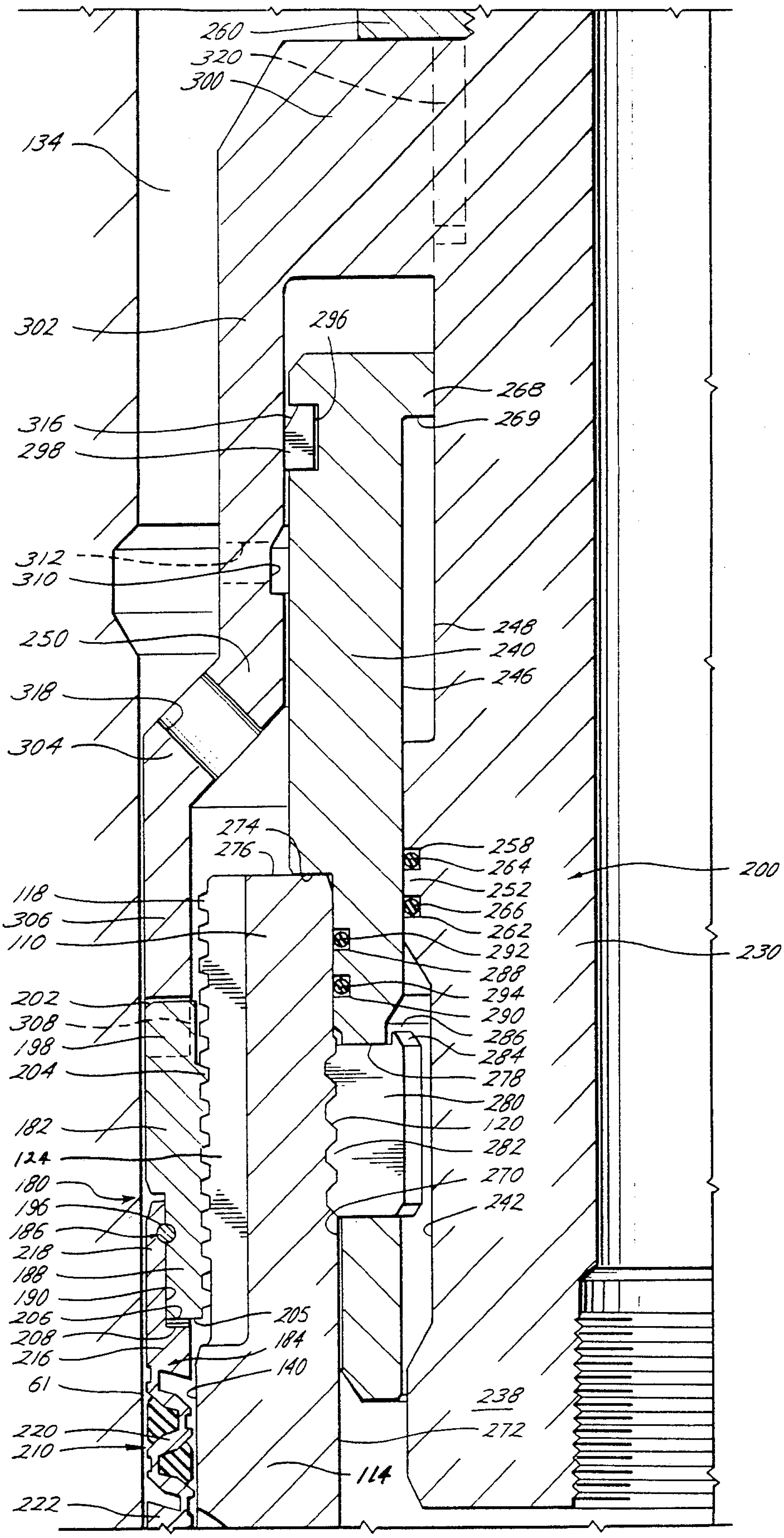


Fig. 2A

Fig. 2B



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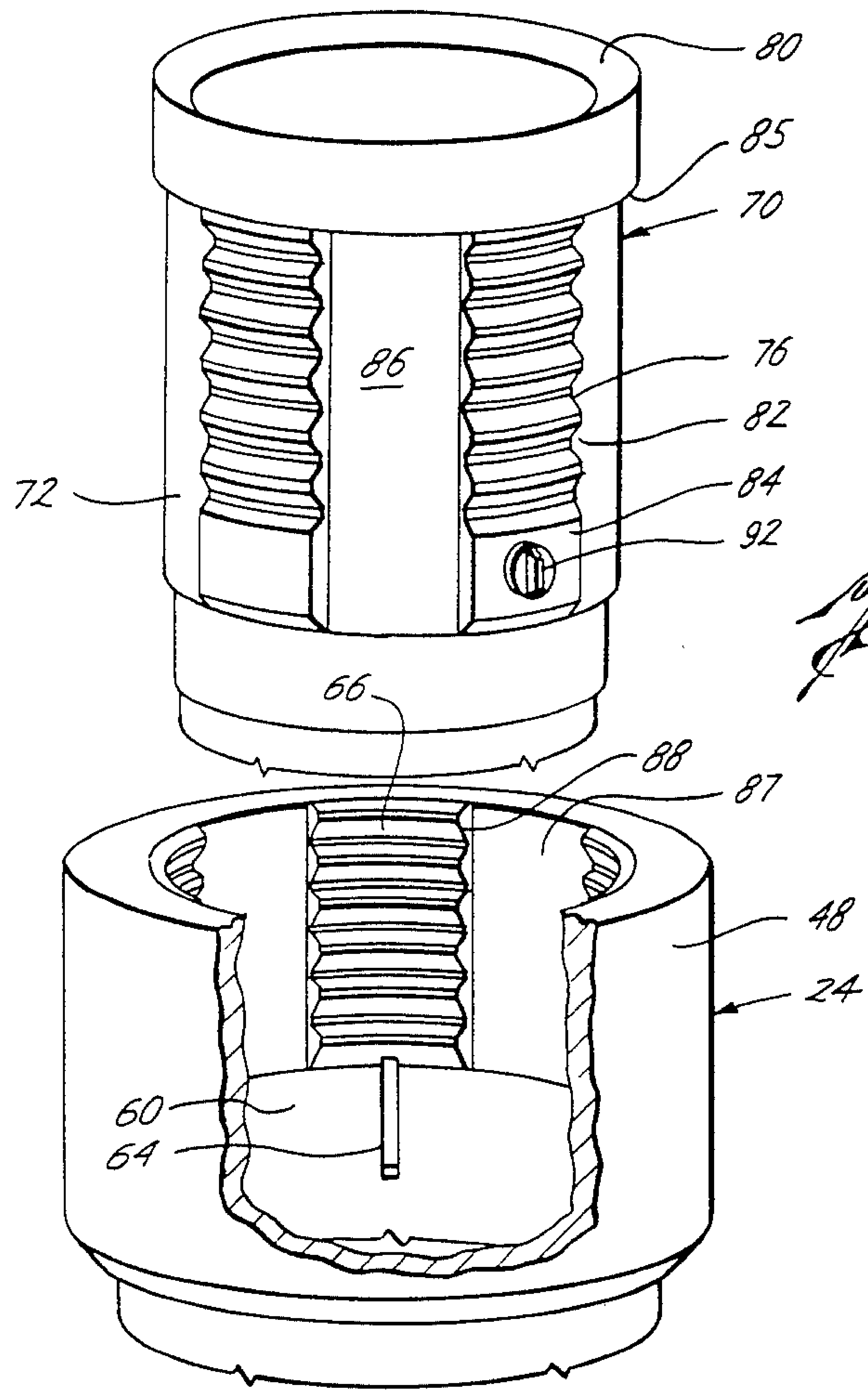
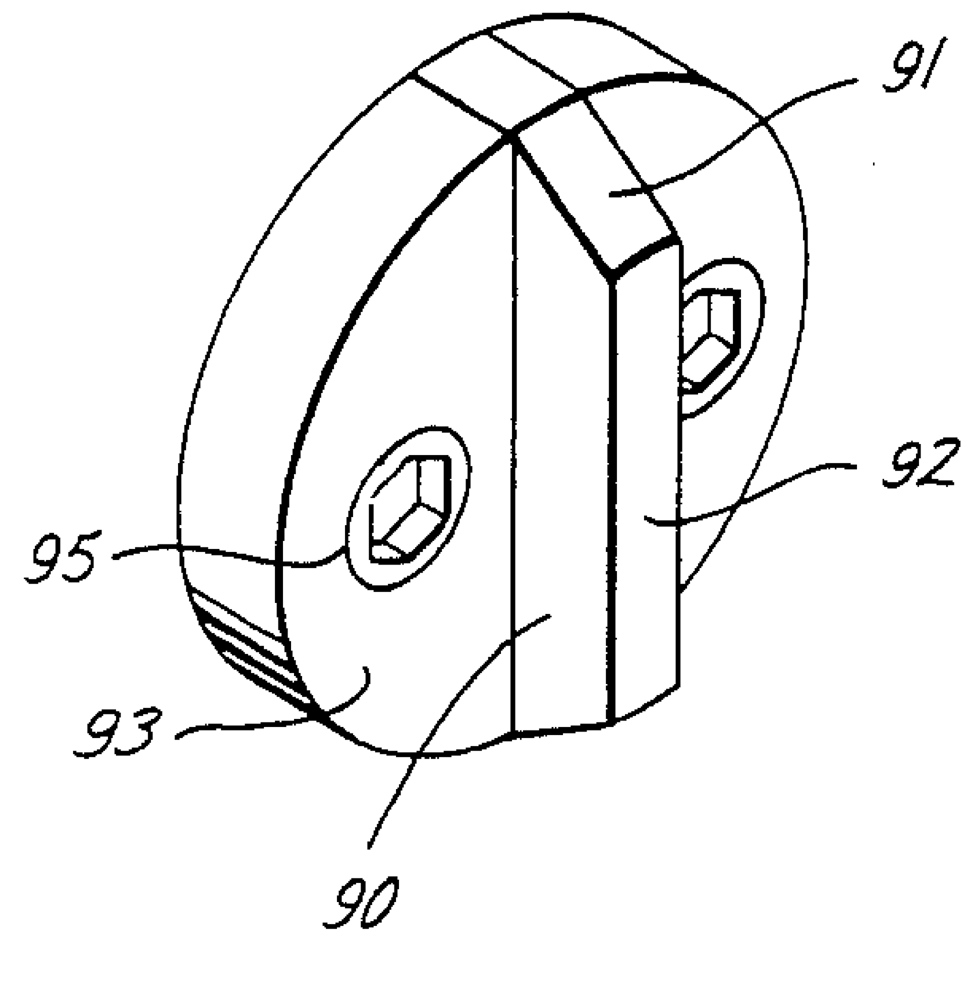


Fig. 3

Fig. 3A



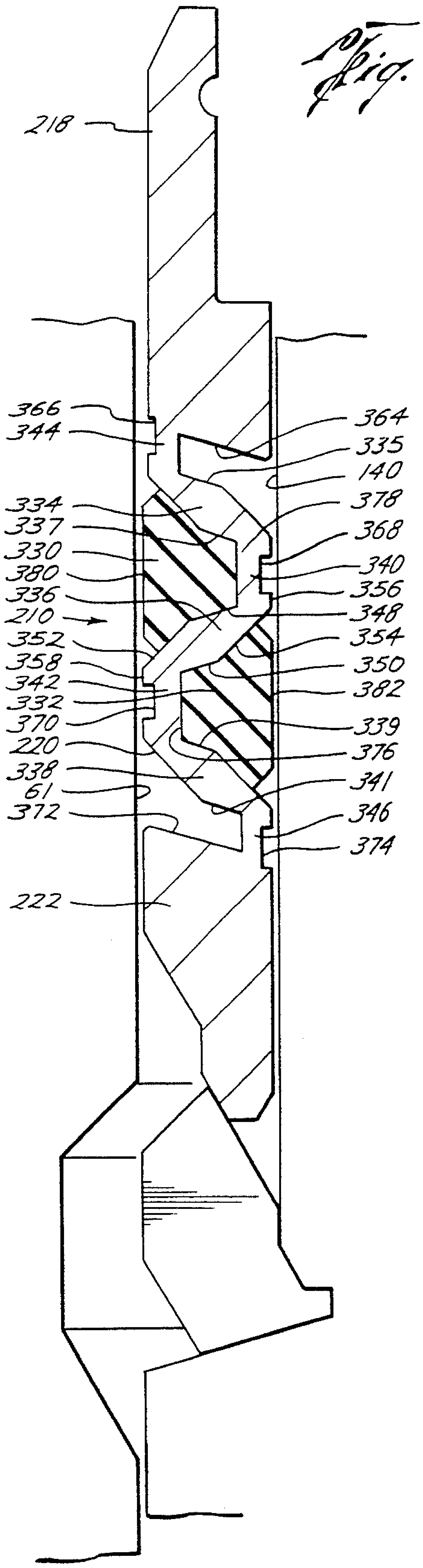

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Fig. 4

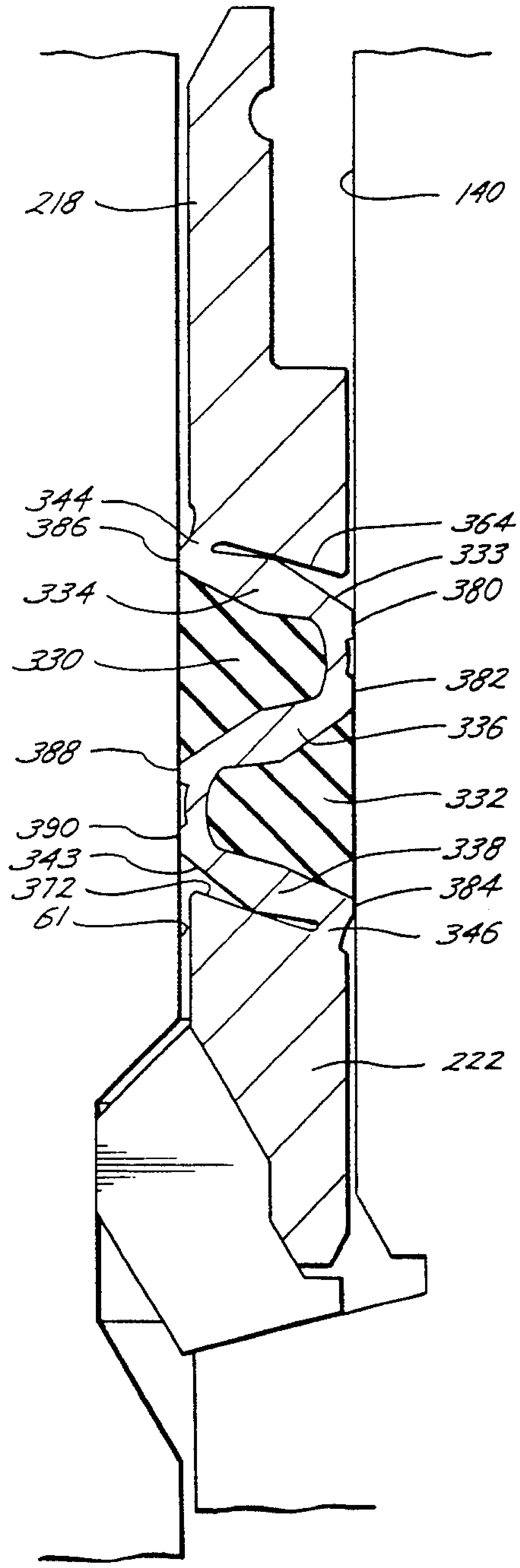
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Fig. 4A

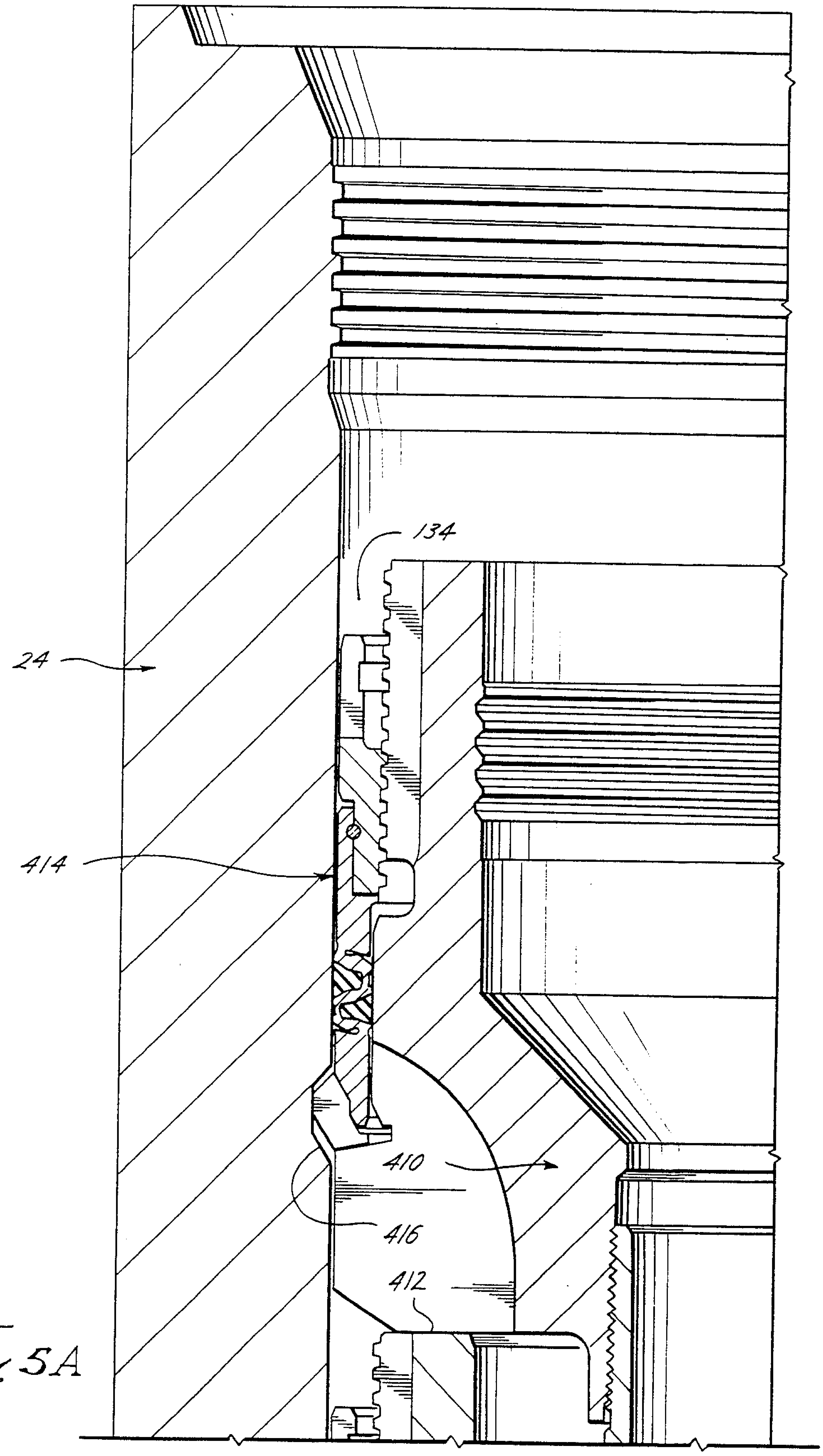

Fig. 5A

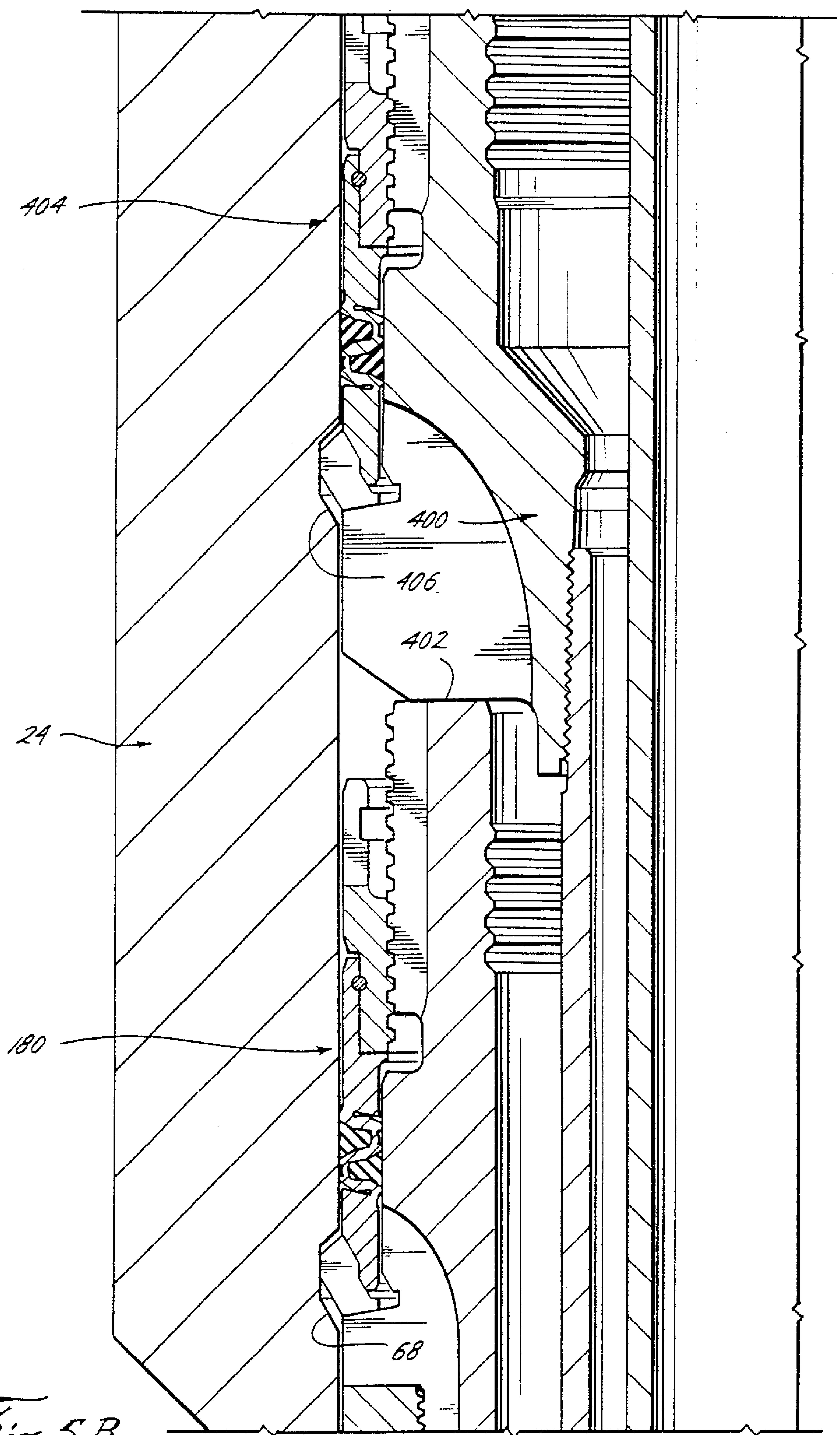

Fig. 5B

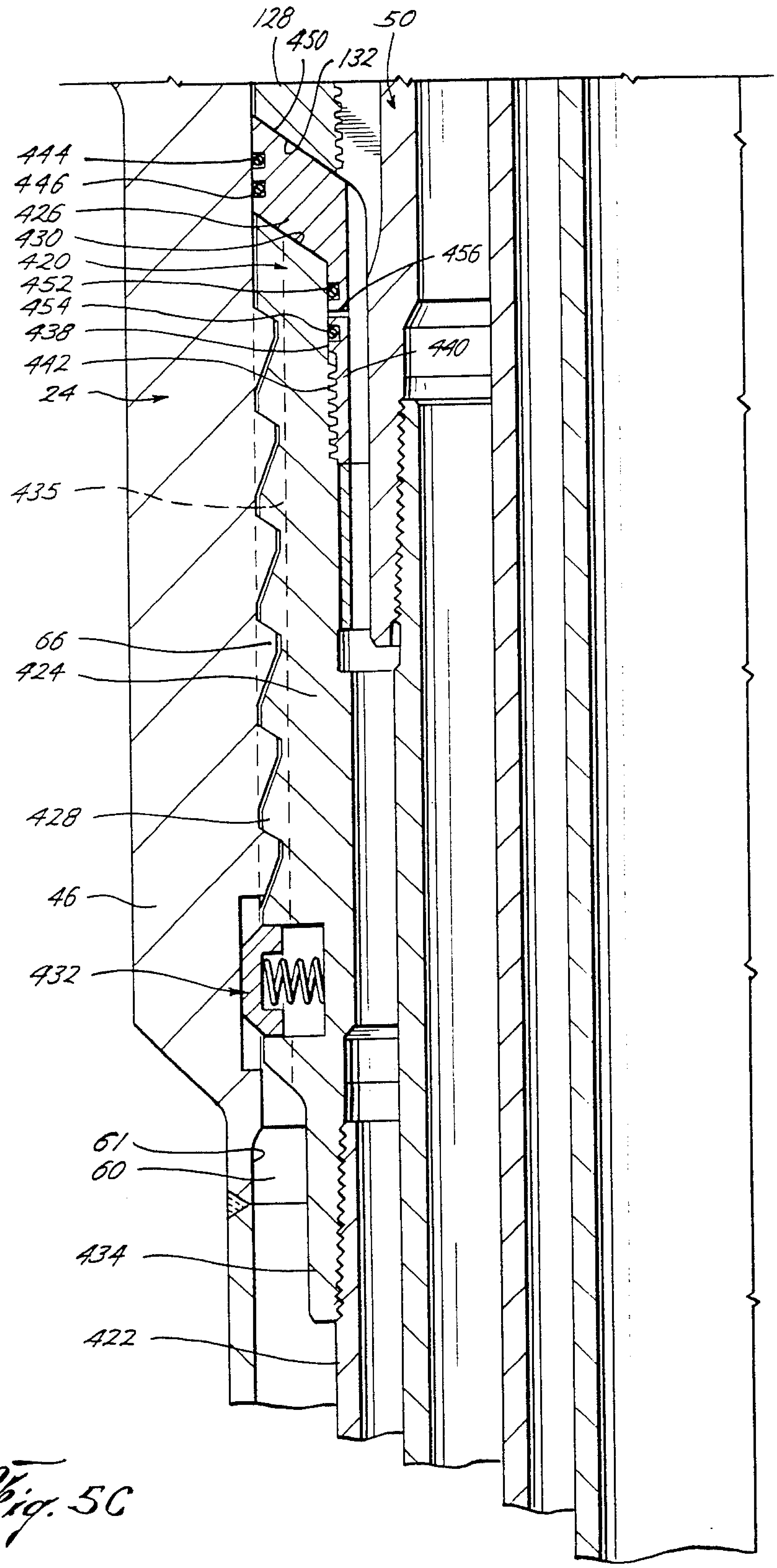
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Fig. 5C

BREECH BLOCK HANGER SUPPORT

BACKGROUND OF THE INVENTION

This invention relates to subsea wellhead systems and more particularly, to methods and apparatus for supporting, holding down, and sealing casing hangers within a subsea wellhead.

Increased activity in offshore drilling and completion has caused an increase in working pressures such that it is anticipated that new wells will have a working pressure of as high as 15,000 psi. To cope with the unique problems associated with underwater drilling and completion at such increased working pressures, new subsea wellhead systems are required. Wells having a working pressure of up to 15,000 psi are presently being drilled off the coast of Canada and in the North Sea in depths of over 300 feet. These drilling operations generally include a floating vessel having a heave compensator for a riser and drill pipe extending to the blowout preventer and wellhead located at the mud line. The blowout preventer stack is generally mounted on 20 inch pipe with the riser extending to the surface. A quick disconnect is often located on top of the blowout preventer stack. An articulation joint is used to allow for vessel movement. Two major problems arise in 15,000 psi working pressure subsea wellhead systems operating in this environment, namely, a support shoulder in the wellhead housing which will support the casing and pressure load, and a sealing means between the casing hangers and wellhead which will withstand and contain the working pressure.

In the past, prior art wellhead designs permitted adequate landing support for successive casing hangers. However, with the increase in pressure rating and the landing and supporting of multiple casing strings and tubing strings within the wellhead, a small support shoulder will not support the load. Although an obvious answer to the problem would be to merely use a support shoulder large enough to support the casing and pressure load, large support shoulders projecting into the flow bore in the wellhead housing restrict access to the casing below the wellhead housing for drilling. In the early days of offshore drilling, 16¾ inch bore subsea wellhead systems required underreaming. At that time, most floating drilling rigs were outfitted with a 16¾ inch blowout preventer system to eliminate the two stack (20 inch and 13⅝ inch) and the two riser system required up until that time. As wellhead systems moved from 5,000 psi to 10,000 psi working pressure, the 18¾ inch, 10,000 psi support shoulder was developed to carry casing and pressure loads and to provide full access into the casing below the wellhead housing.

The second major problem is the sealing means. The sealing means must be capable of withstanding and containing 15,000 psi working pressures. Available energy sources for energizing the sealing means include weight, hydraulic pressure, and torque. Each sealing means requires different amounts of energy to position and energize. Weight is the least desirable because the handling of drill collars providing the weight is difficult and time consuming on the rig floor. If hydraulic pressure is applied through the drill pipe, there is a need for wireline equipment to run and recover darts from the hydraulic-to-actuated seal energization system. If darts are not used, the handling of "wet strings" of drill pipe is very messy and unpopular with drilling crews. If the seal energization means uses the single trip casing hanger technique, the cementing fluid can cause problems in the hydraulic system used to energize the seal. Maintenance is also a problem. Although torque is the most desirable method to energize a seal, there are limitations on the amount of torque which can be transmitted from the surface due to friction losses to riser pipe, the blowout preventer stack, off location, various threads, and the drill pipe itself.

The subsea wellhead system of the present invention overcomes the deficiencies of the prior art and includes many other advantageous features. The system is simple, has less than 50 parts and is suitable for H_2S service. The system has single trip capability but can still use multiple trip methods. All hangers are interchangeable with respect to the outer profile so that they can be run in lower positions. The seal elements are interchangeable and are fully energized to a pressure in excess of the anticipated wellbore pressure. Back-up seals are available. The seals are not pressure de-energized. The hangers can be run without lock downs and the seal elements will seal even if the hanger lands high.

The housing support seat supports in excess of 6,000,000 lbs. (working pressure plus casing weight or test pressure) without exceeding 150% of material yield in compression. The wellhead will pass a 17½ inch diameter bit. The present invention does not attempt to land on two types of seats at once or on two seats at once. Further, the housing support seat is not sensitive to collecting trash during drilling or to collecting trash during the running of a 13⅜ inch casing. Further, the housing support seat does not require a separate trip nor does it drag snap rings down the bore.

The hanger hold down will hold down 2,000,000 lbs. The hanger hold down is positively mechanically retracted when retrieving the casing hanger body and is compatible with single trip operations. The hanger hold down is released for retrieval of the casing hanger when the seal element is retrieved. The hanger hold down is compatible with multiple trip operations and permits the running of the hanger with or without the hold down. The sealing means will work even if the hold down is not used. The hanger hold down is reusable and has a minimum number of tolerances to stack up between hold down grooves.

The sealing means of the present invention will reliably seal an annular area of approximately 18½ inch outside diameter by 17 inch inside diameter and provide a rubber pressure in excess of 15,000 psi (20,000 psi nominally) when the sealing means is energized and the sealing means sees a pressure from above or below of 15,000 psi. The pressure in excess of 15,000 psi is retained in the sealing means after the running tool is removed. The sealing means is additionally self-energized to hold full pressure where full loading force was not applied or where full loading force was not retained. The sealing means will not be pressure de-energized. The sealing means provides a relatively long seal area to bridge housing defects and/or trash. Further, the sealing means provides primary metal-to-metal seals and uses the metal-to-metal seals as backups to prevent high pressure extrusion of secondary elastomeric seals. The sealing means of the present invention positively retracts the metal-to-metal seals from the walls prior to retrieving the sealing means. The elastomeric seals of the sealing means are allowed to relax during retrieval of the packoff assembly and is completely retrievable. The present sealing means provides a substantial metallic link between the top and the bottom of the packing seal area to insure that the lower ring is retrievable. The design allows for single trip operations. There are no intermittent metal parts in the seal area to give irregular rubber pressures. The sealing means provides a minimum number of seal areas in parallel to minimize leak paths. The sealing means is positively attached to the packing element so that it cannot be washed off by flow during the running operations. The design also allows for multiple trip operations and is interchangeable for all casing hangers within a nominal size.

The means to load the sealing means reliably provides a force to energize the sealing means to a nominal 20,000 psi. It allows full circulation if used in a single trip. However, the loading means is compatible with either a single trip operation or multiple trip operation. Further, it is interchangeable for all casing hangers within the wellhead system. The loading means will cause the sealing means to seal even if the casing hanger is set high. Further, it does not release any significant amount of the full pressure load after actuation. The loading means does not require a remote engagement of hold down threads. Further, it has no shear pins. The loading means is reusable and does not have to remotely engage hold down threads on packing nut replacement.

The casing hanger running tool includes a connection between the running tool and casing hanger which will support in excess of 700,000 lbs. of pipe load. The running tool is able to generate an axial force in excess of 900,000 lbs. to energize the sealing means. Further, the running tool is able to tie back into the casing hanger without a left hand torque. The running tool can be run on either casing or drill pipe.

Other objects and advantages of the invention will appear from the following description.

SUMMARY OF THE INVENTION

The present invention relates to a breech block hanger support in a subsea wellhead assembly particularly useful for offshore wells having a working pressure of up to approximately 15,000 psi. The wellhead assembly includes a wellhead, the breech block hanger support, a packoff for sealing the breech block hanger support with the wellhead and another casing hanger, and one or more other casing hangers supported by the breech block hanger support.

The wellhead has a bore of 17 9/16 inches to permit the passage of a standard 17½ inch drill bit. The breech block hanger support with suspended casing is landed and connected to the wellhead for supporting one or more of the other casing hangers within the wellhead and for withstanding and containing the pressure load within the well. Breech block teeth are provided on the wellhead and the breech block hanger support to permit the hanger support to be stabbed into the wellhead and rotated less than 360° for completing the connection therebetween. The breech block teeth include six groupings of six teeth and are spaced-apart no-lead threads. Breech block slots are provided between adjacent groupings of teeth to provide a natural flow way for the passage of well fluids. The breech block hanger support includes an upper annular flange for arresting the downward movement of the breech block hanger support within the wellhead. This annular flange includes flutes aligned with the breech block slots for the passage of well fluids. The flutes are more narrow than the breech block slots to prevent the breech block hanger support from passing through the wellhead.

The upper surface of the annular flange provides a bearing surface for supporting one or more of the other casing hangers. The bearing surface of the hanger support will support the casing and tubing load in addition to a 15,000 psi working pressure. The bearing surface of the breech block teeth is greater than the bearing surface provided by the annular flange of the hanger support for the next casing hanger.

The packoff is provided for sealing the breech block hanger support with the wellhead and with the next casing hanger. The packoff includes means for testing the integrity of the seals of the packoff.

After landing, connecting, sealing, and testing the breech block hanger support, the next casing hanger with casing is landed on top of the breech block hanger support. A holddown and sealing assembly is disposed between the wellhead and the next casing hanger to holddown and seal the next casing hanger. Second and third casing hangers are subsequently run into the well one after another and those hangers are similarly sealed with the wellhead. The breech block hanger support supports the three casing hangers with suspended casing and at the same time, withstands and contains a 15,000 psi working pressure.

Another embodiment of the invention includes the extension of the body of the breech block hanger support whereby a holddown and sealing assembly may be disposed between the breech block hanger support and the wellhead. The holddown and sealing assembly includes a seal portion having a plurality of fustroconical metal links connected together by connector links to form a Z shape. The adjacent metal links form annular grooves for housing resilient elastomeric members. A tool is provided for actuating by torque and hydraulic pressure the holddown and sealing assembly to establish a primary metal-to-metal seal and a secondary elastomeric seal between the breech block hanger support and the wellhead.

BRIEF DESCRIPTION OF THE DRAWINGS

For a detailed description of the preferred embodiment of the invention, reference will now be made to the accompanying drawings wherein:

FIG. 1 is a schematic view of the environment of the present invention;

FIGS. 2A, 2B, and 2C are section views of the wellhead, hanger support ring, casing hanger running tool, pack off and hold down assembly, and a schematic of a portion of the blowout preventer for the underwater well of FIG. 1;

FIG. 3 is an exploded view of the breech block housing seat and a portion of the wellhead of FIG. 2;

FIG. 3A is an enlarged elevation view of the key shown in FIG. 3;

FIG. 4 is a section view of the sealing element in the running position and FIG. 4A is a section view of the sealing element in the sealing position; and

FIGS. 5A, 5B and 5C are section views of the wellhead with the casing hangers of the 16-inch, 13⅜ inch, 9⅝ inch and 7 inch casing strings landed and in the hold down position and in the sealing position.

DESCRIPTION OF THE PREFERRED EMBODIMENT

The present invention is a subsea wellhead system for running, supporting, sealing, holding, and testing a casing hanger within a wellhead in an oil or gas well. Although the present invention may be used in a variety of environments, FIG. 1 is a diagrammatic illustration of a typical installation of a casing hanger and a casing string of the present invention in a wellhead disposed on the ocean floor of an offshore well.

Referring initially to FIG. 1, there is shown a well bore 10 drilled into the sea floor 12 below a body of water 14 from a drilling vessel 16 floating at the surface 18 of the water. A base structure or guide base 20, a conductor casing 22, a wellhead 24, a blowout preventer stack 26 with pressure control equipment, and a marine riser 28 are lowered from floating drilling vessel 16 and installed into sea floor 12. Conductor casing 22 may be driven or jetted into the sea floor 12 until wellhead 24 rests near sea floor 12, or as shown in FIG. 1, a bore hole 30 may be drilled for the insertion of conductor casing 22. Guide base 20 is secured about the upper end of conductor casing 22 on sea floor 12, and conductor casing 22 is anchored within bore hole 30 by a column 32 of cement about a substantial portion of its length. Blowout preventer stack 26 is releasably connected through a suitable connection to wellhead 24 disposed on guide base 20 mounted on sea floor 12 and includes one or more blowout preventers such as blowout preventer 40. Such blowout preventers include a number of sealing pipe rams, such as pipe rams 34 on blowout preventer 40, adapted to be actuated to and from the blowout preventer housing into and from sealing engagement with a tubular member, such as drill pipe, extending through blowout preventer 40, as is well known. Marine riser pipe 28 extends from the top of blowout preventer stack 26 to floating vessel 16.

Blowout preventer stack 26 includes "choke and kill" lines 36, 38, respectively, extending to the surface 18. Choke and kill lines are used, for among other things, to test pipe rams 34 of blowout preventer 40. In testing rams 34, a test plug is run into the well through riser 28 to seal off the well at the wellhead 24. The rams 34 are activated and closed, and pressure is then applied through kill line 38 with a valve on choke line 36 closed to test pipe rams 34.

Drilling apparatus, including drill pipe with a standard 17½ inch drill bit, is lowered through riser 28 and conductor casing 22 to drill a deeper bore hole 42 in the ocean bottom for surface casing 44. A surface casing hanger 50, shown in FIG. 2C suspending surface casing 44, is lowered through conductor casing 22 until surface casing hanger 50 lands and is connected to wellhead 24 as hereinafter described. Other interior casing and tubing strings are subsequently landed and suspended in wellhead 24 as will be described later with respect to FIGS. 5A, 5B and 5C.

Referring now to FIG. 2C, wellhead 24 includes a housing 46 having a reduced diameter lower end 48 forming a downwardly facing, inwardly tapering conical shoulder 52. Reduced diameter lower end 48 has a reduced tubular portion 54 at its terminus forming another smaller downwardly facing, inwardly tapering conical shoulder 56. Conductor casing 22 is 20 inch (outside diameter) pipe and is welded to reduced tubular portion 54 on the bottom of wellhead 24. Conductor casing 22 has a thickness of ½ inch and a 19 inch inner diameter internal bore 62 to initially receive the drill string and bit to drill bore hole 42 and later to receive surface casing string 44 as shown in FIG. 1. Wellhead housing 46 includes a bore 60 having a diameter of approximately 18 11/16 inches, slightly smaller than internal bore 62 of conductor casing 22.

Disposed on the interior of wellhead bore 60 are a plurality of stop notches 64, breech block teeth 66, and four annular grooves (shown in FIG. 5B) such as groove 68, spaced along bore 60 above breech block teeth 66. Breech block teeth 66 have approximately a 17 9/16 inch internal diameter to permit the pass through of the standard 17½ inch drill bit to drill borehole 42.

Wellhead 24 includes a removable casing hanger support seat means or breech block housing seat 70 adapted for lowering into bore 60 and connecting to breech block teeth 66. Housing seat 70 includes a solid annular tubular ring 72 having a smooth interior bore 74, exterior breech block teeth 76 adapted for engagement with interior breech block teeth 66 of wellhead housing 46, an upwardly facing, downwardly tapering conical seat or support shoulder 80 for engaging surface casing hanger 50, and a key assembly 78 for locking housing seat 70 within wellhead housing 46.

Bore 74 of solid ring 72 has an internal diameter of 16.060 inches providing conical support shoulder 80 with an effective horizontal thickness of approximately 1.3 inches to support casing hanger 50. Housing seat 70 has a wall thickness great enough to prevent housing seat 70 from collapsing under a 90,000 psi vertical compressive stress. This is of concern since wellhead 24, because of its size, weight and thickness, is a rigid member as compared to housing seat 70 which is a relatively flexible member.

As shown in FIG. 3, housing seat 70 includes a plurality of groupings 82 of segmented teeth 76 with breech block slots or spaces 86 therebetween for receiving corresponding groupings 88 of segmented teeth 66 in wellhead housing 46 shown in FIG. 2C. Segmented teeth 66, 76 may or may not have leads, but preferably are no-lead teeth. Teeth 66, 76 are not designed to interferingly engage upon rotation of seat 70 for connection with wellhead 24. Wellhead teeth 66 are tapered inwardly downward to facilitate the passage of the bit. If threads 66 were square shouldered or of the buttress type, they might engage the bit as it is lowered through wellhead 24 to drill bore 42 for surface casing 44. Shoulder teeth 76 have corresponding tapers to matingly engage wellhead teeth 66. Groupings 82, 88 each include six rows of segmented teeth approximately ½ inch thick from base to face. The thread area of the six rows of segmented teeth 66, 76 exceeds the shoulder area of support shoulder 80. A continuous upper annular flange 85 on seat 70 disposed above teeth 76 limits the insertion of tooth groupings 82 into spaces 87. Continuous upper annular flange 85 prevents seat 70 from passing through wellhead 24. Lowermost tooth segment 84 is oversized to prevent a premature rotation of seat 70 within wellhead 24 until seat 70 has landed on annular flange 85.

The six rows or groupings 82, 88 of segmented teeth 66, 76 provide an even number of rows to evenly support and distribute the load. Such design evens out the stresses placed on segmented teeth 66, 76. By having six groupings of teeth, segmented teeth 66, 76 may be connected by rotating housing seat 70 30°, i.e., 180° divided by the number of groupings. Should segmented teeth 66, 76 be longer in length, a greater degree of rotation of housing seat 70 would be required for connection. It is preferable that segmented teeth 66, 76 be equal in length so that a maximum amount of contact will be available to support the loads.

Segmented teeth 66, 76 may merely be circular grooves having slots or spaces 86, 87 for connection. Segmented teeth 66, 76 have a zero lead angle and are tapered to increase the thread area so that threads **66, 76** will withstand a greater amount of shear stress. The taper of segmented teeth **66, 76** is greater than 30° and preferably is about 55° whereby the thread area is substantially increased for shear. This tooth profile attempts to equalize the stresses over all of the segmented teeth **66, 76** so that teeth **66, 76** do not yield one at a time.

Teeth **66, 76** may be of the buttress type. A square shoulder on teeth **66, 76** would catch debris and other junk flowing through the well. An added advantage of the breech block connection between wellhead **24** and housing seat **70** is that segmented teeth **76** clean segmented teeth **66** as housing seat **70** is rotated within wellhead **24**. Teeth **76** knock any debris off teeth **66** so that the debris drops into the breech block slots or spaces **86, 87**.

Continuous threads have several disadvantages. Threads require multiple rotations for connection and must be backed up until they drop a fraction of an inch prior to the leads of the threads making initial engagement. Further, threads ride on a point as they are rotated for connection. The breech block connection between housing seat **70** and wellhead **24** avoids these disadvantages. As housing seat **70** is lowered into wellhead **24** on an appropriate running tool, the lowermost tooth segment **84** on seat **70** will engage the uppermost tooth segment of tooth segments **66** on wellhead housing **24**. Seat **70** is then rotated less than 30° to permit groupings **82** on seat **70** to be received within slot **87** between groupings **88** on wellhead **24**. This drop is substantial, as much as 12 inches, and can easily be sensed at the surface to insure that housing seat **70** has engaged wellhead **24** and can be rotated into breech block engagement. Using the breech block connection of the present invention provides a clear indication when housing seat **70** is fully engaged with wellhead **24**. The breech block connection of the present invention has the added advantage of permitting housing seat **70** to be stabbed into wellhead **24** and made up upon a 30° rotation of housing seat **70** to accomplish full engagement between housing seat **70** and wellhead **24**.

Referring now to FIGS. 2C, 3 and 3A, key assembly **78** includes a plurality of outwardly biased dogs **92** each slidingly housed in an outwardly facing cavity **94** in every other lowermost tooth segment **84** of solid ring **72**. Dog **92** has flat sides **90**, upper and lower tapered sides **91**, and a bore **96** in its inner side to receive one end of spring **98**. Washers **93** are mounted by screws **95** in cavity **94** on each side of dog **92** leaving a slot for dog **92**. The other end of spring **98** engages the bottom of cavity **94** to bias dog **92** outwardly. Stop notch **64** is located beneath all six groupings **88** so that dog **92** is positioned on solid ring **72** whereby dog **92** will be adjacent a stop notch **64** in wellhead housing **46** upon the complete engagement of interior and exterior teeth **66, 76** of wellhead **24** and housing seat **70**. Dog **92** will be biased into notch **64** upon the rotation of ring **72** within threads **66** to thereby stop rotation of ring **72**. An aperture **102** is provided through ring **72** and into cavity **94** to permit the release of dog **92**.

In the prior art, the support shoulder for the surface casing hanger was integral with the wellhead housing and was large enough to support the casing and pressure load. However, this prior art integral support shoulder restricted the bore in the wellhead housing for full bore access to casing below the wellhead housing for drilling. To use a sufficiently large integral shoulder for 15,000 psi working pressures, the bore of the integral shoulder would not pass a standard 17½ inch bit. Such subsea wellhead systems required underreaming.

In the present invention, breech block housing seat **70** is an installable support shoulder which need not be installed in wellhead housing **46** until greater working pressures are encountered. Housing seat **70** is not installed until the drilling operation for surface casing **44** is complete, permitting full bore access. Since only nominal working pressures are encountered during the drilling for the surface casing **44**, the larger support shoulder is not needed. After completion of the drilling for the surface casing **44**, breech block housing seat **70** is installed to handle casing and pressure loads of up to 15,000 psi. Thus, sufficient clearance is provided prior to installation of housing seat **70** to pass a 17½ inch bit.

To install breech block housing seat **70**, housing seat **70** is connected to a running tool (not shown) by shear pins, a portion of which are shown at **104**. The running tool on a drill string then lowers housing seat **70** into bore **60** of wellhead **24** until lowermost tooth segment **84** lands on the uppermost tooth segment of tooth segments **66**. Seat **70** is then rotated until teeth groupings **88** on wellhead **24** drop into breech block slots **86** and teeth groupings **82** on ring **72** are received in corresponding slots **87** on wellhead teeth **66**. Continuous annular flange **85** lands on the uppermost tooth segment of segments **66** in wellhead **24**. Housing seat **70** is then rotated by the drill string and running tool until keys **78** are engaged in stop notches **64** to stop rotation. A pressure test may be performed to be sure housing seat **70** is down. Then shear pins holding housing seat **70** to the running tool are sheared at **104** to release and remove the running tool.

FIG. 2C illustrates the landing of surface casing hanger **50** on breech block housing seat **70** within wellhead **24**. Casing hanger **50** has a generally tubular body **110** which includes a lower threaded box **112** threadingly engaging the upper joint of casing string **44** for suspending string **44** within borehole **42**, a thickened upper-section **114** having an outwardly projecting radial annular shoulder **116**, and a plurality of annular grooves **120** (shown in FIG. 2B) in the inner periphery of body **110** adapted for connection with a running tool **200**, hereinafter described.

Referring now to FIGS. 2A and 2B, threads **118** are provided from the top down along a substantial length of the exterior of tubular body **110** for engagement with holddown and sealing assembly **180**, hereinafter described.

The cementing operation for cementing surface casing string **44** into borehole **42** requires a passageway from lower annulus **130**, between surface casing string **44** and conductor casing **22**, to upper annulus **134**, between wellhead **24** and the drill string **236**, to flow the returns to the surface. A plurality of upper and lower flutes or circulation ports **122, 124** are provided through upper section **114** to permit fluid flow, such as for the cementing operation, around casing hanger **50**. Lower flutes **122** provide fluid passageways through radial annular shoulder **116** and upper flutes **124** provide fluid passageways through the upper threaded end of tubular body **110** to pass fluids around holddown and sealing assembly **180**.

Threads **126** are provided on the external periphery of upper section **114** below annular shoulder **116** to threadingly receive and engage threaded shoulder ring **128** around hanger **50**. Shoulder ring **128** has a downwardly facing, upwardly tapering conical face **132** to matingly rest and engage upwardly facing, downwardly tapering conical support shoulder **80** on breech block housing seat **70**. Casing hanger **50** thus lands on housing seat **70** upon engagement of conical face **132** of hanger shoulder ring **128** and housing seat support shoulder **80** whereby housing seat **70** must withstand the resulting casing and pressure load.

Wells, having a working pressure in the range of 15,000 psi, create unique loads on the wellhead supports. Not only must the wellhead support the weight of the casing hangers with their suspended casing and one or more tubing hangers with their suspended tubing, but the wellhead must withstand and contain the 15,000 psi working pressure. Thus, the wellhead must support both the casing and tubing weight and the pressure load. A 15,000 psi working pressure wellhead must have sufficient support and bearing area throughout the wellhead design such that the load does not substantially exceed the yield strength in vertical compression of the material of the wellhead supports. Although at lower working pressures materials having a 70,000 minimum yield are used, a higher strength yield material with an 85,000 minimum yield is normally used for 15,000 psi wellheads. Conservatively assuming a 90,000 vertical compressive stress on the wellhead, the wellhead of the present invention will support over 6,000,000 lbs. of load since the bearing area is in the range of 65 to 70 square inches. Such a bearing area must be consistent throughout the design so that the load does not exceed over 25% of the material yield strength in vertical compression. The bearing area between the lowermost casing hanger **50** and housing seat **70**, and between housing seat **70** and supporting breech block teeth **66** on wellhead **24** must be sufficient to support such loads without substantially exceeding their material yield strength in vertical compression, i.e. over 25% of yield strength. Such a design has been achieved in the wellhead system of the present invention.

To assure sufficient bearing area between casing hanger **50** and seat **70**, hanger shoulder ring **128** has been threaded onto radial annular shoulder **116** projecting from upper section **114** of casing hanger body **110**. Hanger shoulder ring **128** provides a 360° conical face **132** for engaging support shoulder **80** of housing seat **70** thus providing full and complete contact between shoulder **80** and conical face **132**. Without hanger shoulder ring **128**, flutes or circulation ports **122** through shoulder **116** prevent a 360° bearing area between hanger **50** and housing seat **70**. The engagement between support shoulder **80** and conical face **132** provides an excess bearing area determined by the wellhead internal diameter of 17 9/16 inches and the internal diameter of housing seat **70** of 16.060 inches. Thus, the bearing area between shoulder **80** and face **132** is approximately 70 square inches permitting such bearing area to support in excess of 6,000,000 lbs. in load.

Interior and exterior breech block teeth **66, 76** of wellhead **24** and housing seat **70** also have been designed to provide sufficient bearing area to support the anticipated load described above. As described previously, breech block teeth **66, 76** include six groupings **82, 88** of teeth provided on wellhead **24** and housing seat **70**. Each grouping **82, 88** includes six teeth **66, 76** to support the load. The bearing area of breech block teeth **66, 76** is greater than the bearing area between shoulder **80** and conical face **132**. The number of teeth is determined by the loss of bearing area due to the six spaces **86, 87** for receiving corresponding groupings **82, 88** during makeup.

Referring again to FIG. 2C, radial annular shoulder **116** projecting from upper section **114** of hanger body **110** has an upwardly facing, downwardly and outwardly tapering conical cam surface **136** with an annular relief groove **138** extending upwardly at its base. An annular chamber **142** extends from the upper side of groove **138** to an annular vertical sealing surface **140** extending from groove **138** to the lower end of threads **118**. Radial annular shoulder **116** is positioned below annular lock groove **68** in wellhead housing **46** after hanger **50** is landed within wellhead **24**. Cam surface **136** has its lower annular edge terminating just above the lower terminus of groove **68**.

Casing hanger **50** includes a latch ring **144** disposed on radial annular shoulder **116**. Latch ring **144** may be a split ring which is adapted to be expanded into wellhead groove **68** for engagement with wellhead housing **46** to hold and lock down hanger **50** within wellhead **24**. Wellhead groove **68** has a base vertical wall **146** with an upwardly tapered wall and a downwardly tapered wall. Latch ring **144** has a base vertical surface **148** with a downwardly tapered surface of the extent of the upwardly tapered wall of groove **68** and an upwardly tapered surface parallel to the downwardly tapered wall of groove **68** whereby upon expansion of latch ring **144**, the vertical surface **148** of ring **144** engages the vertical wall **146** of groove **68**. Further, latch ring **144** includes a downwardly facing outwardly and downwardly tapering lower camming face **152** cammingly engaging upwardly facing camming surface **136** of radial annular shoulder **116**, an inwardly projecting annular ridge **154** received by annular relief groove **138** in the retracted position, and an upwardly and inwardly facing camming head **156** adapted for camming engagement with holddown and sealing assembly **180**, hereinafter described. Extending between camming head **156** and annular ridge **154** is tapered surface **158** parallel to the wall of chamber **142**.

Projecting annular ridge **154** is received within groove **138** of casing hanger **50** to prevent latch ring **144** from being pulled out of groove **138** as casing hanger **50** is run into the well. It is necessary during the lowering of casing hanger **50** that latch ring **144** pass several narrow diameters such as in blowout preventer **40**. Blowout preventer **40** often includes a rubber doughnut-type seal which does not fully retract thereby requiring casing hanger **50** to press through that rubber seal. If annular ridge **154** were not housed in groove **138**, latch ring **144** might catch at such a narrow diameter and drag along the exterior surface. This might draw latch ring **144** from groove **138** and permit it to slide upwardly around casing hanger **50** until latch ring **144** engages seal means **210**. This would not only prevent the actuation of holddown actuator means **212**, but would also prevent the actuation of sealing means **210**. Annular chamber **142** provides clearance so that groove **138** can receive annular ridge **154**. This profile also provides a step which keeps latch ring **144** from having such an upward load as the load is placed on latch ring **144**.

Holddown and sealing assembly **180** is shown in FIGS. 2B and 2C, engaged with running tool **200** and actuated in the holddown position. Holddown and sealing assembly **180** includes a stationary member **184** rotatably mounted on a rotating member or packing nut **182** by retainer means **186**. Packing nut **182** has a ring-like body with a lower pin **188** and a castellated upper end **198** with upwardly projecting stops **202**. The inner diameter surface of nut **182** includes threads **204** threadingly engaging the external threads **118** of casing hanger body **110**.

Stationary member **184** has a ring-like body **216** and includes a seal means **210** for sealing between the internal bore wall **61** of wellhead **24** and external sealing surface **140** of casing hanger **50**, and a holddown actuator means **212** for actuating latch ring **144** into holddown engagement within groove **68** of wellhead **24**. Ring-like body **216** is a continuous and integral metal member and includes an upper drive portion **218**, an intermediate Z portion **220**, and a lower cam portion **222**.

Upper drive portion **218** includes an upper counterbore **190** that rotatably receives lower pin **188** of packing nut **182**. Retainer means **186** includes inner and outer races in counterbore **190** and pin **188** housing retainer roller cones or balls **196**. Retainer means **186** does not carry any load and is not used for transmitting torque or thrust from packing nut **182** to stationary member **184**. Bearing means **205** is provided above sealing means **210** and includes bearing rings **206**, **208** disposed between the bottom of counterbore **190** and the lower terminal end of pin **188**. Bearing rings **206**, **208** have a low coefficient of friction to permit sliding engagement therebetween upon the actuation of holddown actuator means **212** and sealing means **210**. Thus, bearing means **205** is utilized to transmit thrust from packing nut **182** to stationary member **184**. Retainer balls **196** merely rotatively retain stationary member **184** on packing nut **182**.

Holddown actuator means **212** includes lower cam portion **222** having a downwardly and outwardly facing cam surface **224** (shown in FIG. 2C) adapted for camming engagement with camming head **156** of latch ring **144**, and upper drive portion **218** and intermediate Z portion **220** for transmission of thrust from packing nut **182** to lower cam portion **222**.

Sealing means **210** includes Z portion **220** and elastomeric back-up seals **330**, **332** which will be described in detail with respect to FIG. **4** hereinafter, and upper drive portion **218** and lower cam portion **222** for compressing intermediate Z portion **220**. Sealing means **210** is a combination primary metal-to-metal seal and secondary elastomeric seal. Having a metal-to-metal seal be the primary seal has the advantage that it will not tend to deteriorate as does an elastomeric seal.

Holddown and sealing assembly **180** is lowered into the well on casing hanger **50** by a running tool **200**. Running tool **200** includes a mandrel **230**, which is the main body of tool **200**, a connector body or sleeve **240**, a skirt or outer sleeve **250**, and an assembly nut **260**. Mandrel **230** includes an upper box end **232** with internal threads **234** for connection with the lowermost pipe section of drill pipe **236** extending to the surface **18** and a lower box end **238** also having internal threads. Above box end **238** is located an annular reduced diameter groove portion **242**. Another reduced diameter portion **248** is disposed above groove portion **242** forming an annular ridge **252**. Below upper box end **232** and above reduced diameter portion **248** is a third threaded reduced diameter portion **254** (shown in FIG. 2A) having a diameter smaller than that of portions **242** and **248**.

Connector body or sleeve **240** includes a bore **246** dimensioned to be telescopically received over annular ridge **252** and box end **238**. Connector body **240** is telescopingly received in the annulus formed by mandrel **230** and skirt **250**. Ridge **252** includes annular seal grooves **258**, **262** housing 0-rings **264**, **266**, respectively, for sealing engagement with the inner diameter surface of bore **246**. The top end of connector body **240** includes an internally directed radial annular flange **268** having a sliding fit with the surface of reduced diameter portion **248**. The lower end of connector body **240** has a reduced diameter portion **270** which is sized to be slidingly received by bore **272** of casing hanger **50**. Reduced diameter portion **270** forms downwardly facing annular shoulder **274** which engages the upper terminal end **276** of casing hanger **50** upon landing running tool **200**, holddown and sealing assembly **180** on casing hanger **50** within wellhead **24**. Reduced diameter portion **270** has a plurality of circumferentially spaced slots or windows **278** which slidingly house segments or dogs **280** having a plurality of teeth **282** adapted to be received by grooves **120** of casing hanger **50** for connection of running tool **200** with casing hanger **50**. Dogs **280** have an upper projection **284** received within an annular groove **286** around the upper inner periphery of windows **278**. Above windows **278** are a plurality of seal grooves **288**, **290** housing O-rings **292**, **294** for sealingly engaging the seal bore **272** of casing hanger **50**. Adjacent to the upper exterior end of connector body **240** is a snap ring groove **296** housing snap ring **298** used in the assembly of running tool **200** as hereinafter described. Dogs **280** collapse back into groove portion **242** after lower box end **238** is moved to the lower position, as shown, upon the application of torque on tool **200** to set holddown and sealing assembly **180**.

Skirt or outer sleeve **250** includes a generally tubular body having an upper inwardly directed radial portion **300**, a medial portion **302**, a transition portion **304**, and a lower actuator portion **306**. Portions **300**, **302**, **304** and **306** are contiguous and have dimensions to telescopically receive the upper terminal end **276** of casing hanger **50**, connector body **240** and mandrel **230**. Lower actuator portion **306** has a castellated lower end **308** engaging the upper castellated end **198** of packing nut **182** whereby torque may be transmitted from running tool **200** to holddown and sealing assembly **180**. The inner diameter of actuator portion **306** is sufficiently large to clear the outside diameter of threads **118** of casing hanger **50**.

Medial portion **302** slidingly receives connector body **240**. Portion **302** includes an internal annular groove **310** adapted to receive snap ring **298** mounted on connector body **240** upon disengagement of running tool **200** from holddown and sealing assembly **180** and casing hanger **50**, as hereinafter described. Portion **302** has a plurality of threaded bores **312** extending from its outer periphery to groove **310** whereby bolts (not shown) may be threaded into groove **310** to prevent snap ring **298** from engaging groove **310** during the resetting of running tool **200** on another casing hanger. Snap ring **298** has an upper cam surface **316** for engaging the ends of the bolts. Once connector body **240** is received into the upper portion of the annular area formed by outer sleeve **250** and mandrel **230** whereby snap ring **298** is above annular groove **310**, connector body **240** cannot be removed without snap ring **298** engaging groove **310**. Thus, to remove connector body **240** upon the resetting of running tool **200**, bolts are threaded into bores **312** to close groove **310** and prevent groove **310** from receiving and engaging snap ring **298**. This permits connector body **240** to move downwardly on mandrel 230 for connection to another casing hanger.

Transition portion 304 adjoins actuator portion 306 and medial portion 302 to compensate for the change in diameters. Flow ports 318 are provided in transition portion 304 to permit cement returns to pass through outer sleeve 250 and into annulus 134.

The upper radial portion 300 has its interior annular surface castellated to form a splined connection 320 with mandrel 230 for the transmission of torque.

Referring now to FIGS. 2A and 2B, assembly nut 260 has internal threads 324 for a threaded connection at 322 with threads 235 of reduced diameter portion 254 of mandrel 230. The lower terminal face of assembly nut 260 bears against the upper terminal end of outer sleeve 250 to retain outer sleeve 250 on mandrel 230.

In operation, the packing nut 182 is only partially threaded to threads 118 at the top of casing hanger 50 so that mandrel 230 is mounted in the running position on casing hanger 50. In the running position, annular ridge 252 abuts shoulder 269 formed by radial annular flange 268 on connector body 240. The outer tubular surface of box end 238 is adjacent to and in engagement with the internal side of dogs 280 whereby teeth 282 are biased into grooves 120 of casing hanger 50 preventing the disengagement of running tool 200 and casing hanger 50 as they are lowered into the well on drill pipe 236. The running position of running tool 200 is not illustrated in the figures.

Upon landing face 132 of shoulder ring 128 of casing hanger 50 on support shoulder 80 of housing seat 70 in wellhead 24, surface casing 44 is cemented into place within borehole 42. After the cementing operation is completed, running tool 200 is rotated and torque is transmitted to holddown and sealing assembly 180 to actuate holddown and sealing assembly 180 into the holddown position shown in FIGS. 2B and 2C. Rotation of drill pipe 236 at the surface 18 causes mandrel 230 to rotate which rotates outer sleeve 250 by means of splined connection 320. The torque from outer sleeve 250 is then transmitted to packing nut 182 at the castellated connection of stops 202 of nut 182 and lower end 308 of sleeve 250. Packing nut 182 places an axial load on holddown and sealing assembly 180 causing cam portion 222 of holddown actuator means 212 to move into camming engagement with camming head 156 of latch ring 144. Such camming expands latch ring 144 into wellhead groove 68 for engagement with wellhead housing 46 to hold and lock down casing hanger 50 within wellhead 24 as shown in FIG. 2C. Sealing means 210 has not yet been actuated to seal between upper annulus 134 and lower annulus 130. Latch ring 144 requires only a predetermined camming load for actuation and therefore has a predetermined contractual tension. Sealing means 210 is designed in cross section to insure that sealing means 210 will not be prematurely compressed upon the actuation and camming of latch ring 144 by holddown actuator means 212. The load required to compress sealing means 210 is substantially greater than that required to expand and actuate latch ring 144. Mandrel 230 moves downwardly with skirt 250 upon the actuation of holddown and sealing assembly 180. This downward movement of mandrel 230 releases dogs 280.

For a description of sealing means 210, reference will now be made to FIGS. 4 and 4A showing sealing means 210 in the running and holddown positions and the sealing position, respectively. Sealing means 210 includes metal Z portion 220, upper and lower elastomeric members 330, 332, respectively, and upper drive portion 218 and lower cam portion 222 for compressing Z portion 220 and elastomeric members 330, 332. Metal annular Z portion 220 includes a plurality of annular links 334, 336, 338 connected together by annular metal connector rings 340, 342 and connected to upper drive portion 218 by upper metal connector ring 344 and to lower cam portion 222 by lower metal connector ring 346.

Links 334, 336, 338, together with connector rings 340, 342, 344, and 346, provide a positive connective link from bottom to top between lower cam portion 222 and upper drive portion 218. This positive connective link causes links 334, 336, and 338 to move into a more angled disengaged position from wellhead 24 and casing hanger 50 upon the retrieval and disengagement of sealing means 210 and actuator means 212 from wellhead 24. Further this positive connective link provides a metal connection extending from drive portion 218 to lower cam portion 222 to permit the application of a positive upward load on lower cam portion 222 upon disengagement. Were it not for the advantage of this retrieval, connector rings 340, 342, 344, and 346 may not be required.

Connector rings 344, 346 adjacent drive portion 218 and cam portion 222, respectively, must have a minimum length to ensure the sealing engagement of annular links 334 and 338. If connector rings 344, 346 are too short, there will be insufficient bending to allow links 334, 338 to contact surfaces 61, 140, respectively. Because drive portion 218 and cam portion 222 are massive in size when compared to connector rings 344, 346, the comparative massive body of portions 218, 222 will not bend so as to permit the sealing engagement of links 334, 338. Thus, it is essential that connector rings 344, 346 permit such bending. Connector rings 340, 342, 344, and 346 provide a local high stress contact point throughout metal Z portion 220.

The metal Z portion 220 is made of a very soft ductile steel such as 316 stainless. Such metal would have a yield of approximately 40,000 psi. This yield is less than half the yield of approximately 85,000 psi of the material for wellhead 24 and hanger 50. Upon sealing engagement of metal Z portion 220, metal Z portion 220 plastically deforms while surface 61 of wellhead 24 and surface 140 of hanger 50 tends to elastically deform. Should there be any imperfection in surfaces 61, 140, the ductility of the material of annular Z portion 220 will permit such material to deform or flow into the peaks and valleys of the imperfections of surfaces 61, 140 to achieve a high compression metal-to-metal seal. Thus, metal Z portion 220 is adapted for coining into sealing contact with walls 61, 140 of wellhead 24 and casing hanger 50 respectively, upon actuation.

Upper, intermediate, and lower annular links 334, 336, 338 respectively, each have a diamond-shaped cross-section. Since the cross-section of links 334, 336, 338 is substantially the same, a description of link 336 shall serve as a description of links 334, 338. Annular link 336 includes substantially parallel upper and lower annular sides 348, 350 respectively, with upper side 348 facing generally upward and lower side 350 facing generally downward, substantially parallel inner and outer annular sides 352, 354 respectively, with outer side 352 facing radially outward and inner side 354 facing radially inward, and parallel inner and outer annular sealing contact rims 356, 358 respectively. Annular links 334, 338 have comparable upper and lower sides, inner and outer sides and inner and outer sealing contact rims.

In the holddown position, the sealing contact rims of links **334, 336, 338** are deformed substantially parallel with the bore wall **61** of wellhead housing **46** and the outer wall **140** of casing hanger **50**. Upper connector ring **344** extends from the lower end **364** of upper drive portion **218** to the upper side **335** of upper link **334** to form an annular channel **366**. Metal connector ring **340** extends from the lower side **337** of upper link **334** to upper side **348** of intermediate link **336** to form annular channel **368** and metal connector ring **342** extends from lower side **350** of intermediate link **336** to the upper side **339** of lower link **338** to form annular channel **370**. Lower connector ring **346** extends from the lower side **341** of lower link **338** to the upper end **372** of lower cam portion **222** to form annular channel **374**. Annular channels **366, 368, 370** and **374** between adjacent ridges assist in achieving the bending of Z portion **220** at predetermined locations, namely at connector rings **340, 342, 344**, and **346**. Lower end **364** of drive portion **218** is substantially parallel with the upper side **335** of upper link **334** and upper end **372** of cam portion **222** is substantially parallel with the lower side **341** of lower link **338**. In the running and holddown positions, the outer and inner sealing contact rims have the same diameter as the outer and inner diameters of upper drive portion **218** and lower cam portion **222** respectively.

Upper and lower elastomeric members **330, 332** are molded to conform to the shapes of annular grooves **376, 378** formed by links **334, 336, 338** and are bonded to links **334, 336, 338**. Upper and lower elastomeric members **330, 332** have outer and inner annular vertical sealing surfaces **380, 382** respectively, adapted for sealingly engaging bore wall **61** and outer wall **140** in the sealing position. The upper and lower annular ridges formed by sealing surfaces **380, 382** are chamfered to permit deformation into sealing position of members **330, 332** upon compression. Elastomeric members **330, 332** are also chamfered to permit a predetermined deformation of members **330, 332** between links **334, 336, 338**. Although the cross sections of elastomeric members **330, 332** are substantially the same, inner elastomeric member **332** may be chamfered or trimmed more than outer elastomeric member **330** to avoid any premature extrusion of members **330, 332** prior to links **334, 336, 338** establishing an anti-extrustion seal with bore wall **61** of wellhead **24** and outer sealing surface **140** of casing hanger **50**.

It is preferred that sealing means **210** include at least three links. This number is preferred since it provides an anti-extrusion link for each side of elastomeric members **330, 332**. Also, the three links **334, 336, 338** achieve a symmetry of design. However, sealing means **210** could include one or more links and might well include a series of links capturing a plurality of elastomeric members. Surfaces **364** and **372** of drive portion **218** and lower cam portion **222**, respectively, would preferably have tapers tapering in the same direction as the adjacent links such as links **334** and **338** shown in the preferred design.

The diamond shaped cross section of links **334, 336, 338** permits the mid-portion of links **334, 336, 338** to be very rigid. By having a thick mid-portion, the reduced areas at the ends of links **334, 336, 338** will become the area which will yield or bend such as that area adjacent to connector rings **340, 342, 344, 346**. It is not desirable that links **334, 336, 338** bend or yield at their mid-portion. However, the particular diamond-shaped cross section shown occurs only because of the ease of manufacture of that shape. Links **334, 336** and **338** could have a continuous convex or ellipsoidal shape. This shape might be termed frusto-conoidic. This provides a protuberant center portion. If the cross section of links **334, 336, 338** were of the same thickness, links **334, 336, 338** might tend to bend or bow at their mid-section. Although it is preferred to have a thickened center portion for links **334, 336, 338** to control the point of bending at the rims for a predetermined plastic deformation and to insure there is no distortion at the center of links **334, 336, 338**, links **334, 336, 338** may be frustoconical metal rings with a cross section of even thickness rather than frustoconoidic rings.

Referring now to FIGS. **4** and **4A**, FIG. **4A** illustrates sealing means **210** in the sealing position. Sealing means **210** is compressed as holddown actuator means **212** reaches the limit of its travel against latch ring **144** and packing nut **182** continues its downward movement on threads **118** of casing hanger **50** as shown in FIGS. 2B and 2C.

Metal-to-metal sealing means **210** is series actuated from bottom to top. In other words, the lowest annular link **338** bends and deforms first upon compression of sealing means **210** and is the first link to initiate sealing contact with surface **61** and surface **140**. This series actuation is preferred to limit the drag of upper annular links **334, 336** down surfaces **61, 140** upon actuation if the upper links **334, 336** were to make sealing engagement prior to lower link **338**. It is preferred that there be a balanced force applied to upper annular link **334**.

Elastomeric members **330, 332** provide the initial seal. Elastomeric seals **330, 332** engage surfaces **61, 140** prior to the rims of annular links **334, 336, 338** contacting surfaces **61, 140**. No extrusion of elastomeric seals **330, 332** is to occur past the rims upon the initial compression set of a few thousand psi, i.e., 3,000 psi, of sealing means **210**. Links **334, 336, 338** provide a backup for members **330** and **332**, an anti-extrusion means for such members and are a retainer for such members. Therefore, it is desired that the rims of links **334, 336, 338** engage surfaces **61, 140** prior to the elastomeric members **330** and **332** extruding past the adjacent rims. It is undesirable for such extrusion past the rims to occur prior to the sealing contact of the rims since any elastomeric material between the rims and surfaces **60, 140** may be detrimental to the sealing engagement of links **334, 336, 338**. Thus, as shown and described, the volume of elastomeric material in members **330** and **332** has been calculated and predetermined so that the rims contact surfaces **60, 141** prior to any extrusion of members **330, 332**.

Links **334, 336, 338** are designed to be thin enough to deform into sealing engagement upon a compression set of a few thousand psi. Connector rings **340, 342, 346** form stress points or weak areas around annular Z portion **220** locating the bending of Z portion **220** at predetermined points to cause the inner and outer rims of Z portion **220** to properly sealingly engage bore wall **61** and outer wall **140**. Upon actuation, the rims coin onto bore wall **61** and outer wall **140** to form a metal-to-metal seal between wellhead **24** and casing hanger **50** thereby sealing upper annulus **134** from lower annulus **130** of the well. Sealing means **210** is designed to ensure that there is no fluid channel or leak path between surfaces **61** and **140**.

In the sealing position lower link **338** bends at connector ring **346** causing the outer side **343** of lower link **338** to move downwardly and engage upper end **372** of lower cam portion **222**. The taper of surface **372** of lower cam portion **222** provides an initial starting deformation angle for lower annular link **338**. Surface **372** also ensures that link **338** will not become horizontal so as to prevent the disengagement of link **338** upon the removal of sealing means **210**. As the lower end **364** of drive portion **218** moves downwardly, upper link **334** bends at connector ring **344** causing the inner side **333** of upper link **334** to engage lower end **364** as lower end **364** compressors Z portion **220**. Intermediate link **336** moves from its angled position to a more horizontal position. Elastomeric members **330, 332** are compressed between links **334, 336, 338** and sealingly engage bore wall **61** and outer wall **140**. The inner rims of links **334, 336, 338** make annular sealing contacts with outer wall **140** of casing hanger **50** at **380, 382** and **384** and the outer rims of links **334, 336, 338** make annular sealing contact with bore wall **61** of wellhead **24** at **386, 388,** and **390**. The seal means **210** thus achieves a six point annular metal-to-metal sealing contact. The sealing contact of the inner and outer rims causes links **334, 336, 338** to become antiextrusion rings for elastomeric members **330, 332**. Elastomeric members **330, 332** serve as backup seals to the metal seals.

As links **334, 336, 338** move from their angled position to a more horizontal position upon actuation, each end or each inner and outer rim of links **334, 336, 338** move into engagement with bore walls **61** and **140**. It is not intended that links **334, 336, 338** become horizontal. It is essential that the inner and outer rims of links **334, 336,** and **338** become biased between bore wall **61** of wellhead **24** and outer wall **140** of casing hanger **50**. The inner and outer rims of each link react from the bearing load of the other. For example, as inner rim **356** of link **336** bears against casing hanger wall **140**, this contact places a reaction load on outer rim **358** moving outer rim **358** toward wellhead bore wall **61**. If each link did not have an opposing rim, the link would continue to move downwardly until its side engaged an adjacent link rather than move into sealing engagement with either wall **61** or **140**. This bearing against the inner and outer rims necessitates the prevention of any buckling or bending in the mid-portion of the link. Hence, the diamond-shaped cross section requires that the mid-portion of the link be rigid so that it cannot buckle or relieve itself. Further, if links **334, 336, 338** were permitted to become horizontal, the tolerances between the inside diameter of wellhead **24** and the outside diameter of casing hanger **50** would become critical. Also, where links **334, 336, 338** are not horizontal but at an angle, it is easier to disengage Z portion **220** upon extraction of sealing means **210**. Surface **364** of drive portion **218** and surface **372** of lower cam portion **222** are tapered to prevent links **334** and **338** respectively, from becoming horizontal.

It should be understood that elastomeric seals **330, 332** may not be required where the rims of links **334, 336, 338** sufficiently engage surfaces **61** of wellhead **24** and **140** of casing hanger **50** to permit hydraulic pressure to be applied in annulus **134**. Thus, members **330** and **332** may be eliminated in certain applications where there would be a void between links **334, 336** and **338**. Also, it should be understood that members **330** and **332** may be replaced by a spacer which would permit a predetermined amount of collapse or deformation of links **334, 336, 338**. As disclosed in the present embodiment, elastomeric members **330** and **332** become such a spacer means. Also, the present invention is not limited to an elastomeric material. Members **330** and **332** may be made of other resilient materials such as Grafoil, an all-graphite packing material manufactured by DuPont. Grafoil, in particular, may be used where fire resistance is desired. "Grafoil" is described in the publications "Grafoil - Ribbon-Pack, Universal Flexible Graphite Packing for Pumps and Valves" by F. W. Russell (Precision Products) Ltd. of Great Runmow, Essex, England, and "Grafoil Brand Packing" by Crane Packing Company of Morton Grove, Ill. Such publications are incorporated herein by reference.

It should also be understood that should a metal-to-metal seal not be desired, that channels **368, 370** and **374** might be used to carry elastomeric material to surfaces **61** and **140** to provide a primary elastomeric seal rather than a primary metal-to-metal seal as described in the preferred embodiment. Should the elastomeric seals **330, 332** be the primary seals, annular links **334, 336, 338** become the primary backup for elastomeric seals **330, 332**. These links would become energized backup rings for members **330, 332**. In such a case, the backup seals would not drag down into position.

The present invention is designed for 15,000 psi working pressures and therefore it is the objective of the present invention to achieve a 20,000 psi compression set on seal means **210** whereby seal means **210** is pre-energized in excess of the anticipated working pressure.

In achieving a 20,000 psi compression set, sealing means **210** is actuated by a combination of torque and hydraulic pressure. Initially, an initial torque of approximately 10,000 ft.-lbs. is applied to drill pipe **236** at the surface **18**. Tongs are used to rotate drill pipe **236** so as to transmit the torque to running tool **200** and then thrust to seal means **210**. Particularly, drill pipe **236** rotates mandrel **230** which in turn rotates outer sleeve **250** by means of spline connection **320**. Outer sleeve **250** drives packing nut **182** by means of the castellated connection of lugs **198, 308**. Packing nut **182** bears against drive portion **218** by transmitting thrust through bearing means **205**. Since holddown actuator means **212** has previously reached the limit of its downward travel against latch ring **144** in moving to the holddown position, seal means **210** and specifically, Z portion **220** are compressed between drive portion **218** and lower cam portion **222**. This torque applies an axial force of approximately 150,000 lbs.

As Z portion **220** is compressed between drive portion **218** and lower cam portion **222**, elastomeric members **330, 332** become compressed between links **334, 336, 338** as links **334, 336, 338** move into a more horizontal position. As such compression occurs, elastomeric members **330, 332** begin to completely fill the grooves formed between links **334, 336, 338** housing elastomeric members **330, 332**. The amount of elastomeric material of elastomeric members **330, 332** is predetermined such that as links **334, 336, 338** move into a more horizontal position, links **334, 336, 338** achieve sufficient contact with bore wall **61** of wellhead **24** and outer bore wall **140** of casing hanger **50** to function as metal anti-extrusion means for preventing the extrusion of elastomeric seals **330, 332**. Particularly, the inside annular contact areas **382, 384** prevent the extrusion of inside elastomeric member **332** and annular contact areas **386, 388** prevent the extrusion of outside elastomeric member 330. Thus, an initial anti-extrusion seal is achieved by links 334, 336, 338 before elastomeric members 330, 332 can extrude past their adjacent annular sealing contact areas. It is essential that elastomeric members 330, 332 have the right volume of elastomeric material and the proper configuration so that upon compression of sealing means 210, metal anti-extrusion contact is achieved before the extrusion of elastomeric members 330, 332 past contact areas 382, 384, 386, and 388.

The particular objective of the initial torque is to set elastomeric back-up seals 330, 332 and it is not to establish a metal-to-metal seal between surfaces 61, 140 of wellhead 24 and casing hanger 50 respectively. The initial torque is unable to completely actuate the metal-to-metal seal means 210 because of friction losses in the riser pipe, the blowout preventer stack, the drill pipe itself, and more particularly, because of various thread loads such as at threads 118. Such friction losses limit the compression load which may be applied to sealing means 210 by drill pipe 236.

To achieve the desired compression set of sealing means 210, hydraulic pressure is combined with the torque to set the metal-to-metal seals of sealing means 210. Referring now to FIGS. 2A and 2B, blowout preventer 40 is shown schematically and includes rams 34 with kill line 38 communicating with annulus 134 below blowout preventer rams 34. Convention locates kill line 38 below the lowermost ram. Should the choke line 36, for some reason, be the lowermost line in blowout preventer 40, hydraulic pressure would be applied through choke line 36.

In applying pressure through kill line 38 and into annulus 134, it is necessary to seal off annulus 134. Note in FIG. 2A that kill line 38 is shown in phase with rams 34, but in actuality is manufactured 90° out of phase. In doing so, pipe rams 34 are closed to seal around drill pipe 236, O-ring seals 264, 266 seal between mandrel 230 and sleeve 240, O-ring seals 292, 294 seal between sleeve 240 and the interior surface 272 of hanger 50 and as discussed above, sealing means 210 provide the initial seal across annulus 134. Thus, hydraulic pressure may be applied through kill line 38 and into annulus 134.

Because of the corkscrew effect caused by the application of torque to a drill string such as drill pipe 236, 10,000 ft-lbs of torque is generally considered to be the most torque that can be transmitted through a drill pipe string in an underwater situation. In the present invention, a 10,000 ft-lb torque on drill pipe 236 will establish a seal across annulus 134 which would withstand a few thousand psi of hydraulic pressure. This relatively low pressure seal would then permit the pressurization of annulus 134 to further compress sealing means 210 which in turn increases the sealing engagement in annulus 134 to withstand additional hydraulic pressure. Metal annular E portion 220 with annular links 334, 336, 338, is designed so that annular rings 334, 336, 338 are thin enough to establish a metal-to-metal seal in cooperation with elastomeric seals 330, 332 to withstand a hydraulic pressure of a few thousand psi upon the application of a 10,000 ft-lb torque.

In applying pressure on seal means 210, the effective pressure areas are the diameter of running tool seal 264 less the diameter of drill pipe 236 and in addition thereto, the annular seal area of sealing means 210. Since the annular seal area is fixed for a particular sized wellhead and casing hanger, the principal variable in determining the pressure setting force is the difference in pressure area between the running tool seal 264 and drill pipe 236. Thus, this difference may be varied to permit a predetermined compression setting force on sealing means 210. The difference in diameter may vary, for example, from between 5 inches and 10 inches.

The particular function of the hydraulic pressure is to provide an axial force capable of inducing 20,000 psi into the sealing means 210 without exceeding the pressure design limits of the apparatus in the wellhead system. The function of the torque on nut 182 after hydraulic pressure is applied is to cause nut 182 to follow the travel of sealing means 210 as it moves down under force and prevent its relaxing when the hydraulic force is relieved. It is essential that a high torque, i.e. 10,000 ft-lbs, be maintained in drill pipe 236 so that packing nut 182 follows seal means 210 since otherwise nut 182 might prevent the downward movement of sealing means 210. This procedure is repeated by gradually and continuously increasing the hydraulic pressure until packing nut 182 has been rotated a sufficient number of rotations to insure that a 20,000 psi compression set has been achieved by sealing means 210.

Running tool 200 is a combination tool for applying torque to holddown and sealing assembly 180 and for assisting in the application of hydraulic pressure to holddown and sealing assembly 180. The rotation of drill pipe 236 for the transmission of torque via running tool 200 to holddown and sealing means 180 permits an initial sealing engagement of sealing means 210 in annulus 134 between wellhead 24 and hanger 50 whereby hydraulic pressure may then be applied to annulus 134 to further set sealing means 210. As hydraulic pressure is gradually and continuously increased in annulus 134 through kill line 38, sealing means 210 is further compressed into a greater sealing engagement against surface 61 of wellhead 24 and surface 140 of hanger 50. As this sealing engagement increases, sealing means 210 will seal against an even greater annulus pressure. Thus, pressure through kill line 38 may be gradually increased until sealing means 210 has a compression set of approximately 20,000 psi. The hydraulic pressure applied through kill line 38 and annulus 134 does not exceed the design limits of the system. All systems have a standard working pressure which an operator may not exceed. The system of the present invention is designed for 15,000 psi working pressures and thus the hydraulic pressure in annulus 134 to fully actuate sealing means 210 cannot exceed 15,000 psi although a 20,000 psi compression set is desired. The present invention achieves a 20,000 psi compression set of sealing means 210 without applying a hydraulic pressure exceeding 15,000 psi.

As hydraulic pressure is gradually increased in annulus 134 to achieve a 20,000 psi compression set on sealing means 210, packing nut 182, due to the continuous application of the 10,000 ft-lb torque on drill pipe 236 which is transmitted to skirt 250, follows sealing means 210 downwardly in annulus 134 on threads 204. Upon the release of the hydraulic pressure through kill line 38 and annulus 134, packing nut 182 prevents the release of the 20,000 psi compression set on sealing means 210 due to the engagement of threads 204 with casing hanger 50.

It is essential that elastomeric seals 330, 332 are energized into sealing engagement after the application of the initial torque by drill pipe 236. Unless elastomeric members 330, 332 are engaged, the application of hydraulic pressure through kill line 38 will be lost past sealing means 210 into lower annulus 130. However, the seal of elastomeric members 330, 332 need only be sufficient to seal against an incremental amount of hydraulic pressure through kill line **38** such as 500 psi. After the initial seal is achieved, the application of increasing amounts of hydraulic pressure will further compress Z portion **220** and elastomeric members **330**, **332** to increase the metal-to-metal and elastomeric sealing contact with walls **61**, **140**. Such increased sealing contact will permit the continued increase in hydraulic pressure through kill line **38** for the further actuation of sealing means **210**.

The seal actuation means just described is a simplification of prior art actuator arrangements. Prior art actuators pressure down through drill pipe to actuate an internal porting piston system. A dart seals off the end of the drill pipe bore for the application of pressure through the piston system which in turn applies pressure to the seal. Although such a prior art actuator system could be adapted to the present invention, the arrangement of the present invention has substantial advantages over the prior art.

It may be necessary to increase the initial torque applied to drill string **236** after blowout preventer rams **34** have been closed. Although the rubber contact of rams **34** with drill pipe **236** does not create the friction loss as would a metal-to-metal contact, some additional friction loss will occur. Thus, additional torque, if possible, may be applied to drill string **236** above the initial torque to overcome such friction loss. However, drill pipe **236** will rotate with rams **34** in the closed position. The annulus between the riser and drill pipe **236** contains well fluids which will cause well fluids to be disposed between pipe rams **34** and drill pipe **236** upon closure of blowout preventer **40**. Thus, it is believed that the 10,000 ft-lb torque will not be substantially reduced. If, due to the particular application, the friction between pipe rams **34** and drill pipe **236** must be reduced, a special pipe joint, not shown, may be series connected in drill pipe **236** whereby pipe rams **34** engage a stationary tubular member having a rotating member passing therethrough to transmit torque past rams **34**. Such a special pipe joint would include rotating seals between the stationary member and rotating inner member to prevent the passage of fluid.

Referring now to FIGS. 5A, 5B, and 5C, there is shown the complete assembly of wellhead **24** with 16 inch casing hanger **420**, 13⅝ inch casing hanger **50**, 9⅝ inch casing hanger **400**, and 7 inch casing hanger **410**. Casing hanger **50** is shown in FIG. 5B in the holddown and sealing position described in FIGS. 1–4 with holddown and sealing assembly **180** actuated in the holddown and sealing position. 9⅝ inch casing hanger **400** is shown supported at **402** on top of casing hanger **50**. Casing hanger **400** also includes a holddown and sealing assembly **404** comparable to assembly **180** of casing hanger **50**. 7 inch casing hanger **410** is shown supported at **412** on top of 9⅝ inch casing hanger **400**. Casing hanger **410** includes a holddown and sealing assembly **414** comparable to that of assembly **180**. FIGS. 5A and 5B show the holddown grooves of wellhead **24**, namely holddown groove **68** for casing hanger **50**, holddown groove **406** for casing hanger **400**, and holddown groove **416** for casing hanger **410**.

Casing hangers **400** and **410** do not require a shoulder ring such as shoulder ring **128** for casing hanger **50**. Since casing hangers **400**, **410** support a smaller load, the amount of contact support area required for casing hanger **50** is not needed for casing hangers **400**, **410**. Hanger **50** requires a 100 percent contact area which is not required for hangers **400**, **410**. Further, the shoulders on hangers **400**, **410** are square and shoulder out evenly on top of the supporting hanger.

FIG. 5C discloses an alternative embodiment for removable casing hanger support seat means or breech block housing seat **70** shown in FIG. 2C. Referring now to FIG. 5C, a modified breech block housing seat **420** is shown adapted for lowering into bore **60** and connecting to breech block teeth **66** of wellhead **24**.

In certain areas there are formations below the 20 inch casing which cannot take the pressure of the weight of the mud used to contain the bottom hole pressure. To prevent the rupture of this formation by the weight of the mud, it becomes necessary to run a 16 inch casing string down through that formation before drilling the bore for the 13⅝ inch casing. The modified breech block housing seat **420** suspends the 16 inch casing. Thus, breech block housing seat **420** doubles both as a support shoulder for casing hanger **50** and as a casing hanger for the 16 inch casing **422**.

Housing seat **420** includes a solid annular tubular ring **424** and a packoff ring **426**. Solid annular tubular ring **424** includes exterior breech block teeth **428** substantially the same as breech block teeth **76** described with respect to housing seat **70**. Ring **424** also has an upwardly facing and tapering conical seat or support shoulder **430** adapted for engagement with packoff ring **426**. Ring **424** also includes a plurality of keys **432**, substantially the same as keys **92** shown in FIG. 2C, for locking housing seat **420** within wellhead housing **46**. Ring **424** is provided with a box end **434** for threaded engagement to the upper pipe section of 16 inch casing string **422**.

The upper portion of ring **424** includes a counterbore **438** for receiving the pin end **440** of packing ring **426**. Packing ring **426** includes external threads for threaded engagement with the internal threads in counterbore **438** of ring **424** for threaded connection at **442**. Packing ring **426** includes an upwardly facing support shoulder **450** for engagement with the downwardly facing shoulder **132** of casing hanger **50**. O-ring seals **444** and **446** are housed in annular O-ring grooves around the upper end of packing ring **426** for sealing engagement with bore wall **61** of wellhead **24**. Packing ring **426** also includes O-rings **452**, **454** housed in annular O-ring grooves above thread **442** on pin **440** for sealing engagement with the wall of counterbore **438** of ring **424**. A test port **456** is provided between O-rings **452**, **454** testing the packoff ring **426**.

Since the 16 inch casing string **422** must be cemented, housing seat **420** has flutes or passageways **435** shown in dotted lines on FIG. 5C. Passageways **435** include the natural flow-by of the breech block slots, such as slots **86**, **87** of housing seat **70** and wellhead **24** shown in FIG. 3, and a series of circumferentially spaced slots through continuous annular flange **85** aligned above breech block slots **86**, **87**. The slots of flange **85** are more narrow than breech block slots **86**, **87** to prevent seat **420** from passing through wellhead **24**. Packing ring **426** is provided, after the cementing, to pack off annulus **134**. To test packing ring **426**, the rams of the blowout preventer are closed and the running tool is sealed below the test port **456** and annulus **134** is pressurized. If there is a leak between wellhead housing **46** and packing ring **426** or packing ring **426** and counterbore **438**, it will be impossible to pressure up annulus **134**. Also there will be an increased volume of hydraulic flow into annulus **134** from kill line **38**. It is not necessary that packing ring **426** establish a high pressure seal since at this stage of the completion of the well, most pressures will be in the range of less than 5,000 psi.

It should be understood that one varying embodiment would include making housing seat **70** and casing hanger **50** one piece whereby seat **70** and hanger **50** could be lowered and disposed in wellhead **24** on one trip into the well. Hanger **50**, for example, could include breech block teeth for direct engagement with wellhead breech block teeth **66**.

Another varying embodiment would include extending the longitudinal length of the tubular ring **424** of housing seat **420** whereby sealing means **210** and/or actuator holddown means **212** could be disposed directly on housing seat **420** and between seat **420** and wellhead **24** for sealing and/or holddown engagement with wellhead **24**. In such a case, packing ring **426** would no longer be required.

Because many varying and different embodiments may be made within the scope of the inventor's concept taught herein and because many modifications may be made in the embodiments herein detailed in accordance with the descriptive requirements of the law, it should be understood that the details herein are to be interpreted as illustrative and not in a limiting sense. Thus, it should be understood that the invention is not restricted to the illustrated and described embodiment, but can be modified within the scope of the following claims.

We claim:

1. A hanger-support member for supporting at least one pipe hanger within a wellhead of a well, the pipe hanger having a first string of pipe attached thereto, and for suspending a second string of pipe within the well, the wellhead having a plurality of circumferentially spaced-apart groupings of tooth segments projecting into the wellhead bore for engagement with the hanger-support member, comprising:

a tubular body received within the wellhead;

a plurality of circumferentially spaced-apart groupings of tooth segments disposed on the periphery of said tubular body and adapted for releasably engaging the tooth segments of the wellhead;

shoulder means on said tubular body adapted for engagingly supporting the pipe hanger; and

attachment means on said tubular body for attaching the second string of pipe to said tubular body.

2. The hanger-support member as defined by claim **1** wherein said shoulder means includes a bearing area capable of supporting the load of the pipe hangers and pipe suspended within the wellhead and a 15,000 psi working pressure.

3. The hanger-support member as defined by claim **1** wherein said shoulder means includes a bearing area capable of supporting the load of the pipe hangers and suspended pipe together with the working pressure of the well without substantially exceeding the material yield strength in vertical compression of said tubular body.

4. The hanger-support member as defined by claim **1** wherein said shoulder means includes a bearing area capable of supporting a vertical compressive load in excess of six million pounds.

5. The hanger-support member as defined by claim **1** wherein said shoulder means includes an annular support shoulder having an effective horizontal thickness of at least 1.3 inches.

6. The hanger-support member as defined by claim **1** wherein said shoulder means includes a tapered annular shoulder having a taper angle greater than 30 degrees.

7. The hanger-support member as defined by claim **1** and further including lock means for locking said tubular body within the wellhead.

8. The hanger-support member as defined by claim **1** and including means for releasably connecting a running tool to said tubular body.

9. The hanger-support member as defined by claim **1** wherein said groupings of tooth segments on each of said wellhead and tubular body are adapted for threaded engagement with each other upon rotation of said tubular body less than one revolution.

10. The hanger-support member as defined by claim **1** wherein said releasable engagement between said tooth segments of the wellhead and tubular body is actuated upon a 30 degree rotation of said tubular body.

11. The hanger-support member as defined by claim **1** wherein said groupings of tooth segments of the wellhead and tubular body include breech block teeth.

12. The hanger-support member as defined by claim **1** wherein said groupings of tooth segments of the wellhead and tubular body include teeth having a profile equalizing the stresses over all of said teeth.

13. The hanger-support member as defined by claim **1** wherein said attachment means includes threads for threadingly engaging the second string of pipe.

14. An apparatus for supporting a hanger suspending a first string of pipe and for suspending a second string of pipe within a borehole, comprising:

a head member;

a hanger-support member telescopically received within said head member and having a bearing area adapted to supportingly engage the hanger, said hanger-support member further having means for threadingly engaging the second pipe string for suspending the second pipe string within the borehole;

a plurality of circumferentially spaced-apart groupings of no-lead threads on the inner circumference of said head member and on the outer circumference of said hanger-support member;

the thread on each member being in alignment with the spaces between the threads on the other member upon telescopic insertion of said hanger-support member into said head member, said threads being engaged with each other upon rotation of said hanger-support member to prevent said members from moving axially apart upon the application of an axial force thereon;

whereby said hanger-support member may be engaged with said head member for supporting the hanger and first string of pipe and for suspending the second string of pipe within the borehole.

15. An apparatus for suspending a string of pipe within a well, comprising:

a head member;

a support member having means for attaching said support member to the pipe string for suspending the pipe string within the well;

said support member being insertable into said head member;

tooth means provided on each of said head and support members for engaging one another and releasably connecting said members together on said support member being rotated;

said tooth means comprising a plurality of circumferentially spaced groupings of teeth on the inner periphery of said head member and the outer periphery of said support member, said groupings of said support member being adapted to pass intermediate said groupings of said head member during insertion of said support member into said head member, said teeth of said groupings of said support member being adapted to engage said teeth of said groupings of said head member upon such rotation of said support member.

16. The apparatus as defined by claim **15** wherein said teeth are fully engaged upon rotation of said support member less than one revolution.

17. The apparatus as defined by claim **15** wherein said teeth have a zero lead angle and are tapered to increase the shear area of said teeth.

18. The apparatus as defined by claim **15** wherein said teeth on said support member do not interferingly engage said teeth on said head member.

19. The apparatus as defined by claim **15** wherein said teeth have a non-square shoulder profile for preventing the accumulation of well debris on said teeth.

20. The apparatus as defined by claim **15** wherein said groupings of teeth include tooth segments whereby upon rotation into engagement, the rotating tooth segments of said support member clean said tooth segments on said head member.

21. The apparatus as defined by claim **15** wherein said teeth have a tooth profile for equalizing the stresses over all of said teeth.

22. The apparatus as defined by claim **15** wherein said teeth all have an equal length, the number of groupings on said head member equal the number of groupings on said support member, and each of said members have an even number of said groupings, whereby upon engagement, the stresses and loads are evenly distributed between the teeth.

23. The apparatus as defined by claim **15** wherein each of said members includes six groupings of teeth and six spaces between said groupings.

24. The apparatus as defined by claim **15** wherein each of said groupings each includes six rows of teeth.

25. The apparatus as defined by claim **15** and including a tooth on said support member having an axial width greater than the other support member teeth for preventing a premature threaded engagement between said members.

26. The apparatus as defined by claim **15** and including telescoped unthreaded areas of cylindrical configuration on each of said members.

27. The apparatus as defined by claim **15** wherein said groupings of teeth on said head member have substantially the same circumferential extent as said groupings of teeth on said support member.

28. The apparatus as defined by claim **15** and including anti-rotation means for preventing relative rotation of said members upon complete engagement of said teeth on said support member with said teeth on said head member.

29. The apparatus as defined by claim **28** wherein said anti-rotation means includes a stop on one of said members in engagement with the other said member.

30. The apparatus as defined by claim **28** wherein said anti-rotation means is effected upon rotation of said support member less than one revolution.

31. The apparatus as defined by claim **28** wherein said anti-rotation means includes a moveable element on one of said members positioned within a cavity in the other said member.

32. The apparatus as defined by claim **31** wherein said moveable element may be moved to allow disengagement of said members by relative rotation of said members without relative axial movement, followed by relative axial movement of said support member away from said head member in the absence of relative rotation.

33. The apparatus as defined by claim **31** wherein said support member includes means for moving said moveable element into disengagement.

34. The well apparatus of claim **15** wherein the passage of said groupings of teeth on said support member intermediate said groupings of teeth on said head member provide indication that said tooth means is engaged upon rotation of said support member.

35. The apparatus as defined by claim **15** and including a sealing assembly for sealing between said head member and said support member comprising:

a plurality of frustoconical-shaped metal rings stacked in series, each ring alternating in frustoconical taper;

an annular shoulder mounted on said support member;

an actuator member reciprocally mounted on said support member, said annular shoulder and said actuator member having correlative, oppositely disposed surfaces engaging the end rings of said stack upon sealing engagement;

said metal rings, annular shoulder, and actuator member having an outer diameter smaller than the diameter of the bore of said head member;

actuation means for applying an axial force on said actuator member causing said actuator member to engage said stack of metal rings and move the inner and outer edges of said rings into metal-to-metal sealing engagement with said support member and said head member.

36. The seal assembly as defined by claim **35** wherein said metal rings have a sufficient radial width for the inner and outer edges of said metal rings to interferingly and sealingly engage said support member and said head member and to deform to a larger cone angle.

37. The seal assembly as defined by claim **35** wherein said metal rings are compressed beyond their yield point between said annular shoulder and actuator member.

38. The seal assembly as defined by claim **35** and including annular links between said metal rings, annular shoulder, and actuator member forming a positive connective link between said annular member and said actuator member.

39. The seal assembly as defined by claim **38** wherein said adjacent metal rings form an annular groove for housing an elastomeric seal.

40. The seal assembly as defined by claim **35** and including spacer means disposed between adjacent metal rings.

41. The apparatus as defined by claim **35** and including:

torque transmission means engaging said actuator member to transmit torque and rotate said actuator member;

said actuator member threadingly engaging said support member whereby as torque is transmitted to said actuator member in one direction, said actuator member travels downwardly on said support member a sufficient distance to energize said seal assembly into sealing engagement;

hydraulic means for applying hydraulic pressure to said seal assembly whereby said metal rings of said seal assembly are energized into metal-to-metal sealing engagement with said head member and said support member;

said actuator member following the actuation of said sealing assembly downward on said support member to prevent the release of said sealing assembly upon the removal of the hydraulic pressure.

42. A well apparatus for suspending pipe within a well and for supporting a plurality of stacked pipe hangers suspending pipe within the well, comprising:

a head member;

a support member having a first bearing area adapted to engage the lowermost stacked pipe hanger, said support member being attached to the top pipe section of a pipe string;

tooth means provided on each of said head and support members for releasably connecting said members together, said tooth means having a second bearing area for supporting said support member on said head member;

said first and second bearing areas each having sufficient area whereby the load of the pipe hangers and suspended pipe together with the working pressure of the well does not substantially exceed the material yield strength in vertical compression of said support and head members.

43. The well apparatus as defined by claim **42** wherein said head member has a bore of 17 9/16 inches for receiving a standard $17\frac{1}{2}$ inch drill bit to drill the wellbore for the pipe suspended by the lowermost stacked pipe hanger.

44. The well apparatus of claim **42** wherein said head and support member are made of a high strength yield material having an 85,000 psi minimum yield.

45. The well apparatus of claim **42** wherein said bearing areas are capable of supporting a load in excess of six million pounds.

46. The well apparatus as defined by claim **42** wherein said first bearing area includes a tapered annular shoulder on said support member having a taper angle greater than 30 degrees.

47. The well apparatus as defined by claim **42** wherein said tooth means includes a plurality of segmented circular grooves on each of said members, said segmented grooves of said support member being adapted to pass intermediate said segmented grooves of said head member.

48. An apparatus for suspending a first pipe string within a well and for supporting a pipe hanger suspending a second pipe string within the well, comprising:

a wellhead member;

a hanger-support member telescopingly received within said wellhead member, said hanger-support member threadingly engaging the upper pipe section of the first pipe string for suspending the first pipe string within the well;

a plurality of circumferentially spaced-apart groupings of no-lead threads on the inner circumference of said wellhead member and on the outer circumference of said hanger-support member;

said groupings of threads on said wellhead member being engaged with said groupings of threads on said hanger-support member upon rotation of the hanger-support member less than 360°, thereby connecting said hanger-support member to said wellhead member;

said hanger-support member having an upwardly facing conical seat;

a packing ring having a lower cylindrical portion and an upper annular shoulder flange, said shoulder flange having a downwardly facing surface for engaging the upwardly facing conical seat;

said cylindrical portion of said packing ring having external threads for threaded engagement with interior threads on said hanger-support member;

seal means for sealing between said hanger-support member and said packing ring;

other seal means for sealing said shoulder flange with said wellhead member;

said packing ring having an upper bearing surface adapted for engagement with the pipe hanger.

49. The apparatus as defined by claim **48** and including means for testing said seal means and said other seal means.

50. The apparatus as defined by claim **49** wherein said seal means includes upper and lower O-rings housed in said cylindrical portion of said packing ring and said testing means includes a test port extending between said upper and lower O-rings.

51. The apparatus as defined by claim **47** and further including flutes extending longitudinally through said tooth means.

* * * * *

UNITED STATES PATENT AND TRADEMARK OFFICE

CERTIFICATE OF CORRECTION

PATENT NO. : 4,488,740

DATED : DECEMBER 18, 1984

INVENTOR(S) : BENTON F. BAUGH, HERMAN O. HENDERSON, JR., JOHN H. FOWLER, and ARTHUR AHLSTONE

It is certified that error appears in the above—identified patent and that said Letters Patent is hereby corrected as shown below:

Column 16, line 5: change "frusto-conoidic" to --frustoconoidic --.

Column 19, line 56: delete "E" and insert --Z --.

Claim 14, column 24, line 45: change "thread" to --threads --.

Signed and Sealed this

Twenty-eighth **Day of** *May 1985*

[SEAL]

Attest:

DONALD J. QUIGG

Attesting Officer *Acting Commissioner of Patents and Trademarks*

UNITED STATES PATENT AND TRADEMARK OFFICE
CERTIFICATE OF CORRECTION

PATENT NO. : 4,488,740

DATED : DECEMBER 18, 1984

INVENTOR(S) : BENTON F. BAUGH, ET AL.

It is certified that error appears in the above—identified patent and that said Letters Patent is hereby corrected as shown below:

In column 15, line 34, change "380, 382" to -- 381, 383 --.

In column 15, line 37, change "380, 382" to -- 381, 383 --.

In Figure 4, change "380" to -- 381 -- and change "382" to -- 383 --.

Signed and Sealed this

Twenty-second Day of March, 1988

Attest:

DONALD J. QUIGG

Attesting Officer

Commissioner of Patents and Trademarks